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TITLE   **Cost Effectiveness of CO2 Mitigation Technologies and Policies in the Electricity Sector**

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**Engineering and Public Policy**

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# Cost Effectiveness of CO$_2$ Mitigation Technologies and Policies in the Electricity Sector

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IN

ENGINEERING & PUBLIC POLICY

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# Abstract

In order to find politically feasible ways to reduce greenhouse gas emission emissions, governments must examine how policies affect a variety of stakeholders. The costs and benefits of low carbon technology options are unique and affect different market participants in different ways. In this thesis, we examine the cost effectiveness of carbon mitigation technologies and policies from the social perspective and from the perspective of consumers.

In Chapter 2, we perform an engineering-economic analysis of hybridizing concentrating solar thermal power with fossil fuel. We examine the cost effectiveness of substituting the solar power for new coal or gas and find the cost of mitigation to be approximately ~$130/tCO$_2$ to ~$300/tCO$_2$.

In Chapter 3, we quantify some externalized social costs and benefits of wind energy. We estimate the costs due to variability and transmission unique to wind to have an expected value of ~$20/MWh.

In Chapter 4, we quantify the cost effectiveness of a renewable portfolio standard and a carbon price from the perspective of consumers in restructured markets. We find that both that the RPS can be more cost effective than a carbon price for consumers under certain circumstances: continued excess supply of capacity, retention of nuclear generators, and high natural gas prices.

In Chapter 5, we examine the implications of lowering electricity sector $CO_2$ emissions in PJM through a Low Carbon Capacity Standard (LCCS). We estimate that an LCCS would supply the same amount of energy (105,000 GWh) as the RPS's in PJM and an additional ~10 GW of capacity. We find that the LCCS could be more cost effective for consumers than an RPS if it lowered capacity prices.

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# Chapter 1: INTRODUCTION

Policy-makers seek technologies and policies to mitigate greenhouse gas emissions and reduce the risk of climate change. In order to find politically feasible policies, it is necessary to understand the costs and unintended consequences of policies. Quantifying the costs of greenhouse gas mitigation in the electricity sector is becoming increasingly complex due to both rapid technological advancements and changes in the structure of electricity markets. The focus of this thesis is to quantify the cost effectiveness of carbon mitigation technologies and policies in the electricity sector for a variety of stakeholders.

The electricity infrastructure in the United States was built by vertically integrated utilities that were regulated by government authorities. The passage of PURPA in 1978 opened electricity generation up to "Qualified Facilities", beginning a very slow process to make electricity markets more open and competitive [1]. In the late 1990's and early 2000's, riding the wave of deregulation that had been successful in other industries, some states in the U.S. "restructured"—rendering electricity as a commodity to be traded openly and competitively [1].

The effect of restructuring has been profound. Figure 1-1 below shows the types of capacity installed in the U.S. since 1930. In the wake of restructuring, natural gas developers rushed in to take advantage of opportunities in the energy market—only to find that the market was oversupplied because so many others did the same.
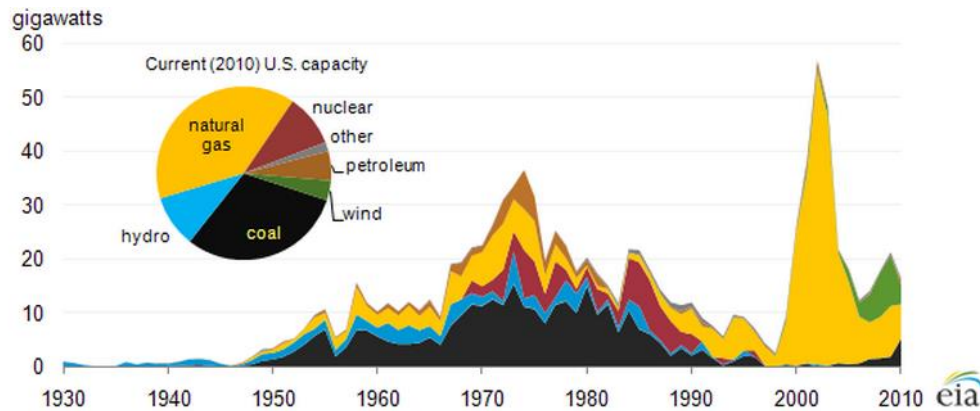
Figure 1-1: Capacity installations in the U.S. since 1930. [2]

Restructured markets have led to unforeseen events (Figure 1-1 and the California Energy Crisis, for example) and have issues that were not originally envisaged. For instance, the primary revenue source of generators, energy market profits, has in recent years been reduced by low natural gas prices [3] and relatively flat demand for electricity [4]. The combined effects of excess capacity, low gas prices, and flat demand have regulators wondering how they are going to incent new capacity given the current market structure [5]. In just a decade and a half, the problems of restructured markets have flipped: instead of unprecedented development of new capacity due to foreseen energy market opportunities, market prices are depressed, forcing many regions to consider additional revenue through new capacity markets (if they don't already have them).

At the same time that policy makers are dealing with the new realities of electricity markets, they are examining ways to mitigate greenhouse gas emissions cost effectively. In assessing these options, maturation of restructured electricity markets has been critical. Restructured electricity markets contain several markets that place a value on electricity services: energy (on different time scales), regulation/ancillary services, transmission, and capacity.

Though it does not appear that restructured markets have actually had their intended effect on electricity prices [6], it is clear that they have been good for producing academic

research data.  The costs and benefits of low carbon technology options are unique, and these sub-markets have assisted in quantifying their contribution to electricity services.  With the hindsight of what has been learned from the history of electricity markets as well as recent energy technology advancements, this thesis quantifies the cost of carbon mitigation technology and policies over the following four research topics:

In Chapter 2, we perform an engineering-economic analysis of hybridizing concentrating solar thermal power with fossil fuel in an Integrated Solar Combined Cycle (ISCC) generator. We estimate the cost of the solar energy and also the cost of mitigation if replacing new coal or natural gas generation.

In Chapter 3, we quantify the external costs and benefits of wind energy in PJM.  Using our own dispatch model and estimates from literature, we estimate the operational costs and transmission costs due to wind not typically included in power purchase agreements.  We also quantify the value of reduced criteria pollutants and carbon dioxide emissions.

In Chapter 4, we examine two policies, a renewable portfolio standard and a carbon price, and quantify the cost effectiveness of these policies in restructured markets from the consumer's perspective.

In Chapter 5, we examine a policy called a Low Carbon Capacity Standard using PJM as an example.  We quantify how much capacity and low carbon energy the policy would supply compared to a Renewable Portfolio Standard.  We compare the consumer's costs of these policies based on possible capacity market reactions.

# References

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# Chapter 2: CAN HYBRID SOLAR-FOSSIL POWER PLANTS MITIGATE $CO_2$ AT LOWER COST THAN PV OR CSP?

## ABSTRACT

Fifteen of the United States and several nations require a portion of their electricity come from solar energy. We perform an engineering-economic analysis of hybridizing concentrating solar thermal power with fossil fuel in an Integrated Solar Combined Cycle (ISCC) generator. We construct a thermodynamic model of an ISCC plant in order to examine how much solar and fossil electricity is produced and how such a power plant would operate, given hourly solar resource data and hourly electricity prices. We find that the solar portion of an ISCC power plant has a lower levelized cost of electricity than stand-alone solar power plants given strong solar resource in the US southwest and market conditions that allow the capacity factor of the solar portion of the power plant to be above 21%. From a local government perspective, current federal subsidies distort the levelized cost of electricity such that photovoltaic electricity is slightly less expensive than the solar electricity produced by the ISCC. However, if the cost of variability and additional transmission lines needed for stand-alone solar power plants are taken into account, the solar portion of an ISCC power plant may be more cost effective.

## 2.1 INTRODUCTION

Many governments around the world provide incentives for solar energy. Of the 29 US states that have renewable portfolio standards (RPS), 15 have solar provisions [1]. Given the specific solar requirements states have invoked and the broader emphasis on solar energy, we seek to determine the cost effectiveness of hybridized solar/thermal systems compared to other solar technologies that comply with the requirements, specifically solar photovoltaics (PV) and concentrated solar thermal power (CSP).

**Integrated Solar Combined Cycle Technology.**

Integrated Solar Combined Cycles (ISCC) are natural gas combined cycle (NGCC) power plants hybridized with solar thermal energy to boost the output of the heat recovery steam generator [2]. The principal advantage to hybridization for solar power is the ability to directly offset fossil fuel energy without having to pay for a power block or transmission lines dedicated to solar energy. The solar field is made up of parabolic troughs, which have mirrors that reflect solar rays onto an evacuated glass tube carrying heat transfer fluid (HTF) [3] designed to absorb solar energy. The power block is essentially the components at the center of a typical thermal based power plants: boiler, heat exchangers, steam turbine, condenser, etc. The power block of a stand-alone CSP plant is an appreciable investment, accounting for approximately 40% to 50% of the capital costs [4] [5]. Assuming that the capacity factor of stand-alone CSP plants are around 25%, sharing a power block with a fossil fuel power plant significantly increases its utilization. Additionally, since maintenance personnel are already on hand to monitor and maintain the power block, maintenance costs assigned to the solar portion are reduced relative to stand-alone solar plants [6]. Figure 2-1 shows an illustration of the concept.
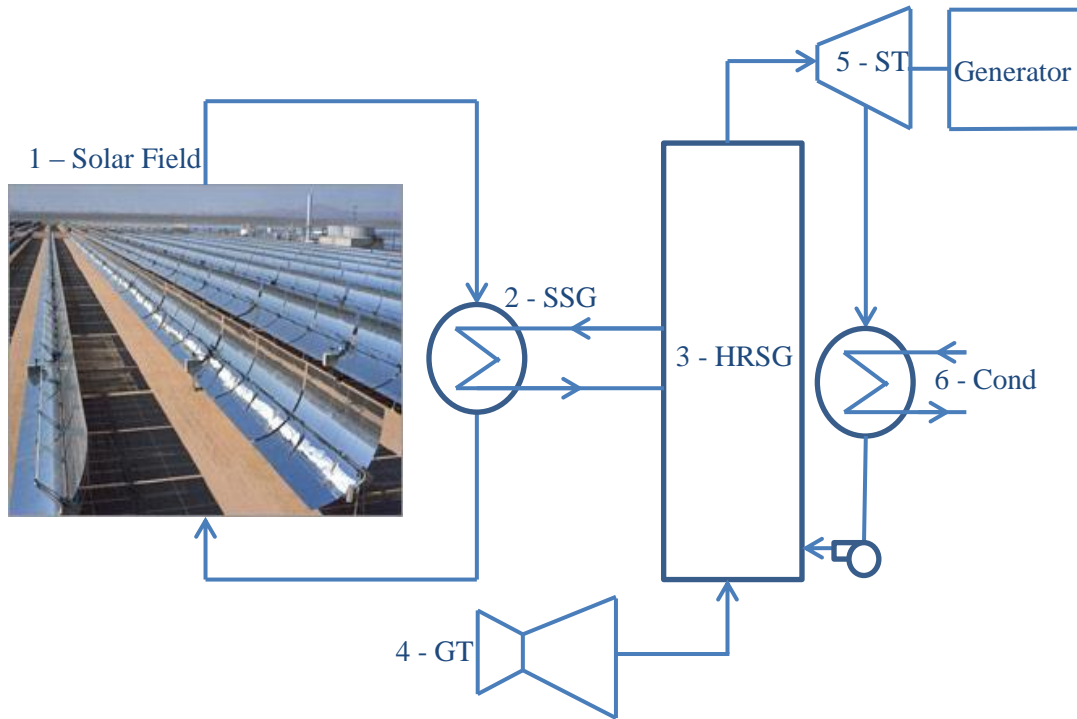
Figure 2-1: Diagram of an ISCC Plant, after Flagsol [7]. 1. Parabolic Trough Solar Field [8]; 2. Solar Steam Generator (SSG); 3. Heat Recovery Steam Generator (HRSG); 4. Gas turbine and generator (GT); 5. Steam Turbine (ST) and generator; 6. Condenser. Solar thermal energy is integrated into the HRSG. Heat transfer fluid (HTF) is heated in the solar field by parabolic trough-shaped mirrors. Hot HTF is then used to make steam in a heat exchanger before the steam returns to the HRSG. Use of natural gas to directly heat steam, also known as duct firing, occurs in the HRSG.

We assume the plant in which we would integrate solar thermal energy would have "duct firing" capability. NGCC plants with duct firing capability have an oversized steam turbine in which the full capacity may be utilized only by directly heating steam with a natural gas burner. This direct heating takes place in the HRSG (no. 3 in Figure 2-1 above). Because duct firing utilizes direct heating (Rankine cycle) instead of a combined cycle, using duct firing lowers the overall efficiency of the plant. However, the duct firing is utilized only when grid prices are high and the marginal benefit of increased MWh production outweighs the slightly higher marginal cost per MWh caused by duct firing.

With ISCC capability, solar energy is used to reduce the quantity of natural gas used in duct firing or to add generation without the energy penalty of duct firing. When solar resources are high, the combined cycle can run at full capacity with a lower heat rate than base-load

without duct firing (Table 2-1). Replacing natural gas duct firing with solar energy is an advantage for combined cycle plants because the marginal costs are lower than other NGCC plants. Therefore, as demand increases, an ISCC plant will be dispatched before a NGCC plant.

**Development of ISCC Plants**

The concept of hybridizing solar thermal power plants was first used in 1986 in some of the Solar Electric Generating System (SEGS) plants [9]. However, these were not combined cycle power plants but Rankine cycle plants with parallel natural gas boilers.

Hybrid solar thermal with NGCC's has become more mature. Plants have been constructed in Italy, Iran, Morocco, and Algeria with solar capacities of 5 MW, 17 MW, 20 MW, and 25 MW, respectively [10] [11] [12] [13]. Florida Power and Light retrofitted one of its NGCC plants in 2010 to make the equivalent of a 75 MW solar plant [14]. General Electric recently bought an interest in eSolar and is developing an ISCC plant in Turkey. ISCC plants are being developed in the U.S., India, Mexico, and Egypt [15] [16] [17] [18].

WorleyParsons prepared a comprehensive set of reports in 2009 on ISCC technology for the Electric Power Research Institute (EPRI) [6]. The reports allowed us to make design decisions for the ISCC plant model and to validate our model's efficiency and costs. EPRI divided the research into solar augmentation for NGCC or for coal plants. The present paper focuses on integration with natural gas plants because we believe that relatively low natural gas prices due to shale gas combined with stricter EPA rules will cause NGCC plants to dominate future development.

## 2.2 METHODS

**Selection of Solar Technology**

We elected to model parabolic trough plants without storage because the technology is relatively mature and performance and cost data are available. Power tower technology may be preferable to parabolic troughs because the thermal medium used in a power tower can reach higher temperatures, thus increasing steam cycle efficiency. However, the modeling of power towers is far more difficult and uncertain with the larger vendors (BrightSource, SolarReserve, and eSolar) all having unique designs with uncertain costs.

**Design of the ISCC Plant and Thermodynamic Model**

It was necessary to build a thermodynamic model to calculate marginal fuel costs, solar electric generation, and fossil electric generation as the solar resource varied. The EPRI reports [6] provided a basic understanding of the design and operation of an ISCC plant. However, to design the thermodynamic model, we extracted technical data from the Victorville 2 Hybrid Power Project Application for Certification for the California Energy Commission (CEC) [19] . The application gives three different heat balances: base-load, duct-firing, and duct-firing with solar. A heat balance reveals the gas and steam flows at each major part of the power plant steam cycle. It also shows the temperature, pressure, and energy content of the fluids.

In agreement with the recommendation of the EPRI reports, the solar steam was injected into the high pressure steam drum for the Victorville 2 Hybrid Power Project permit application. The thermodynamic properties of the steam and gas were given for most points in the heat balance diagrams, and we constructed a complete thermodynamic model using MATLAB and Cantera software [20]. A detailed description of the construction, use, and assumptions of the thermodynamic model is available in the supporting information (SI) on page 48.

The validation results of our thermodynamic model are shown in Table 2-1.

Table 2-1: Efficiency and MW output comparison of Victorville 2 CEC application and constructed thermodynamic model used for this paper.

| | Base Load | | Duct Firing | | Solar and Duct Firing | |
|---|---|---|---|---|---|---|
| | Efficiency (LHV / HHV) | MW | Efficiency (LHV / HHV) | MW | Efficiency (LHV / HHV) | MW |
| CEC Application for Certification | 55.2 / 49.7 % | 463 | 52.6 / 47.4 % | 563 | 58.8 / 53.0 % | 563 |
| Constructed Model | 54.9 / 49.4 % | 463 | 52.9 / 47.7 % | 567 | 59.2 / 53.3 % | 564 |

To ensure that assumptions were not adjusted solely to meet the data points in Table 2-1, we devised a method to separate the contributions of the solar and fossil electricity.

**Computing the Renewable Fraction**

In order to receive renewable energy credits, the CEC requires that hybrid plants "…submit with its application … a proposal for an appropriate method to measure the renewable fraction of the facility's generation" [21].

The thermodynamic model allows us to determine the renewable portion at varying solar and duct-firing loads. The method we use to find the renewable electricity is straightforward: if we add heat from the CSP unit to a fixed amount of gas input, the difference in power produced is solar. For example, at base load, the combined cycle uses about 140 thousand pounds per hour (3180 MMBTU/hr) of gas and produces approximately 460 MW. When 145 thermal MW of solar energy are sent to the power block with the same gas input, the output of the plant increases to approximately 510 MW. The difference, 50 MW, is the solar electricity produced. Similarly, one of the three heat balances submitted to the CEC for the Victorville 2 Hybrid Power Project used 20 thousand pounds per hour (454 MMBTU/hr) of natural gas for duct firing and 145 thermal MW of solar energy to produce approximately 560 MW. If the solar energy was removed and we used the same amount of gas for duct firing, only 510 MW of electricity would

be produced.  Constructing the thermodynamic model allowed us to perform this calculation (SI

page 43).

**Economic Model**

With the ability to model output and efficiency with varying loads of solar thermal

energy, with or without duct firing, an economic model can be constructed.  This economic

model simulates the behavior of a plant operator maximizing marginal profits.  The simulations

are needed to determine the private and public economics of the power plant.  A capacity factor

is needed to estimate levelized cost of electricity (LCOE), and this capacity factor is determined

by expected plant operation.  A block diagram of the economic model is shown in Figure 2-2.

Hourly Solar Thermal Output to Power
Block Extracted from NREL's Solar
Advisor Model

Hourly Grid Price Data from CAISO Grid

Thermodynamic Model runs plant to
maximize hourly marginal profits.  Plant
either does not run, runs at base load, or
runs with duct firing with whatever solar
energy is available.

Hourly (8760) Profit and Performance Data are aggregated

Annual Operation Statistics used to calculate Capacity Factor, Net
Present Value, Levelized Cost of Electricity, and Cost of Mitigation

Figure 2-2: Block diagram of Economic Model

The amount of solar energy sent to the power block is determined by NREL's Solar Advisor

Model (SI page 54).  The grid price used is the median node price for each hour in the California

Independent System Operator (CAISO) region in 2010 (SI page 40) [22].  Every hour, one of

three policies is followed: run at base-load, run with duct firing, or do not run at all.  The policy

that maximizes marginal profits is chosen for that hour.  The economic model computes how the

plant is operated (how many MWh are produced) given marginal gas prices and marginal electricity prices.

**Parametric Study Varying Price of Gas and Electricity**

We present our results as a parametric study varying the price of natural gas and electricity. Both the price of natural gas and the price of electricity are of importance to both the solar and fossil side of the power plant. In order to use the solar energy, the gas turbine of the power plant must be active. Without heat from the gas turbine, solar heat alone does not provide enough energy to keep the quality of the steam exiting the steam turbine above 0.9 (More information in the SI on page 45).

Natural gas price varied between $2 to $12 per MCF in the past decade [23]. The average price of electricity has varied significantly over the past decade in California [24]. Between 2005 and the recession of 2008, the average price varied from $62/MWh to $81/MWh. After the recession, the average wholesale price varied from $37/MWh to $40/MWh. Our sensitivity analysis varied the price of electricity from $35/MWh to $85/MWh. To vary the price of electricity for the parametric study, we multiply the observed hourly [24] data by a constant to produce the desired average annual price.

## 2.3  RESULTS

**Capacity Factor**

The economic viability of the power plant is dependent on how many MWh are produced. Therefore, the first result we present, Table 2-2, is the capacity factor of the solar side and the overall capacity factor of the entire power plant. The capacity factor is defined as the number of MWh produced divided by the number of MWh that could have been produced if the plant ran at capacity for all 8760 hours of the year. We assumed the plant would be constructed

in Phoenix, Arizona.  We also assumed an outage rate of 5% to account for the effect of planned

and unplanned maintenance on MWh produced.

Table 2-2: Capacity Factor of the ISCC Power Plant / Solar Portion of ISCC Power Plant
(Location: Phoenix)

| | | Average Wholesale Price of Electricity [$/MWh] | | | | | |
|---|---|---|---|---|---|---|---|
| | | $ 35 | $ 45 | $ 55 | $ 65 | $ 75 | $ 85 |
| Price Of Gas [$/MCF] | 2 | 87 / 22 % | 89 / 22 % | 89 / 22 % | 90 / 22 % | 90 / 22 % | 90 / 22% |
| | 4 | 58 / 19 % | 80 / 21 % | 85 / 22 % | 87 / 22 % | 88 / 22 % | 89 / 22% |
| | 6 | 16 / 8 % | 43 / 16 % | 67 / 20 % | 80 / 21 % | 84 / 21 % | 86 / 22% |
| | 8 | 6 / 2 % | 15 / 7 % | 35 / 15 % | 55 / 19 % | 71 / 21 % | 79 / 21% |
| | 10 | 4 / 1 % | 7 / 2 % | 14 / 7 % | 29 / 12 % | 45 / 17 % | 61 / 20% |
| | 12 | 3 / 1 % | 4 / 1 % | 7 / 2 % | 14 / 6 % | 26 / 11 % | 39 / 15% |

The capacity factor for the solar portion of the power plant is close to the observed ~25%

capacity factor for CSP generators.  Since the solar side of the plant can run only while the

power block is available, the capacity factor is slightly lower due to an outage rate of 5% on the

fossil side of the ISCC plant.  Additionally, stand-alone CSP plants are expected to have a higher

capacity factor because of a higher solar multiple (SI page 54).

The ISCC capability raises the capacity factor slightly (~2%) when compared to an

NGCC plant under market conditions suitable for NGCC development.  The boost to the

capacity factor of the overall ISCC plant is limited because of the infrequency of solar energy.

Also, the observed CAISO grid price remains too low in the mornings of the spring and early

summer for the plant to run, even with solar energy lowering the marginal cost per MWh.

**Economic Assumptions**

The assumptions we used for the capital costs and maintenance are shown in Table 2-3.

Table 2-3: Capital Costs, Maintenance Costs, and Lifetime of Plant ($2010 USD)

|  | NGCC [25] [26] | Solar Thermal [27] [4] [6] (Trough, No Storage) | Solar PV [25] [26] [28] [29] [30] | Solar Part of ISCC [6] [4] |
|---|---|---|---|---|
| Capital Costs $/kW | 1000 ± 100 | 5800 ± 500 | 4400 ± 1000 | 3900 ± 600 |
| Fixed Maintenance Costs $/kW-year | 5.8 ± 1 | 65 ± 15 | 25 ± 10 | 30 ± 10 |
| Lifetime of Plant (Years) | 25 | 25 | 20 | 25 |

Note: The cost estimate for PV is based on the cost per AC watt. Cost estimates for PV are frequently quoted in $/Watt$_{DC}$. To arrive at the cost per watt AC, we multiply the DC cost estimates by 1.15 for the AC to DC capacity difference. Therefore, the mid-value for capital costs for PV we garnered from studies was $3.8/W$_{DC}$.

To calculate the levelized cost of electricity and the net present value of the NGCC and ISCC plants, we used the following economic assumptions:

| | |
|---|---|
| Private Discount Rate: | 12% |
| Social Discount Rate: | 3% |
| Equity Ratio: | 65% |
| Fossil Portion Depreciation | Straight line over lifetime of plant |
| Renewable Portion Depreciation | Accelerated over 5 years |
| Federal Tax Rate | 34% |
| State Tax Rate | 4.2% |
| Interest Rate | 5.8% |
| Investment Tax Credit (Renewable Portion) | 30% |
| Location of power plant unless noted otherwise | Phoenix, Arizona, U.S. |

The solar portion of the ISCC cost estimate in Table 2-4 includes the components of the solar plant (solar field, solar boiler, and piping to connect power block to solar boiler). However, in addition to the solar components, we assumed in our economic analysis that the solar portion pays a commensurate amount for part of the capital costs of the power block. Additionally, we assume the plant does not receive any payments for regulation or spinning reserves. Costs for permitting or new transmission lines are not included in the capital cost estimates. For PV, we assumed a time period of two years from start of construction to commercial operation, and for all thermal based plants, we assumed three years. For PV, we assumed that the cells degraded at a rate of 1% per year [31].

**Levelized Cost of Electricity (LCOE)**

We computed the LCOE as described above, and present the unsubsidized levelized cost of electricity using a 3% discount rate. Since this result is from the social perspective, no subsidies or taxes were included. The costs incurred include the capital costs, finance costs, and fixed and variable maintenance costs. More detailed LCOE information is documented in the SI on page 58.

We also used the same methods as used for the ISCC plant to calculate the LCOE of a PV and CSP plant in Phoenix, Arizona. The only exception to our method above is a reduced construction time for PV plants as mentioned above. The PV and CSP prices do not require a parametric study because the marginal costs of stand-alone solar plants are essentially zero. As long as the grid price is positive or the power purchase agreement has a fixed price for electricity, the solar plant may run whenever solar resources are available. The resulting LCOE for PV and CSP was $190/MWh and $210/MWh, respectively. Table 2-4 below shows the unsubsidized LCOE for the solar portion of the ISCC power plant.

**LCOE When Subsidies are Included (State or Public Utilities Commission Perspective)**

Subsidies for renewable energy have a large effect on their net cost. From a Public Utilities Commission (PUC) perspective, these subsidies are granted by the federal government, and may be considered "free money" for the term of the subsidy program. We again use a 3% discount rate, but now take into account the investment tax credit and accelerated depreciation (i.e. difference in tax burden if standard depreciation was used). Table 2-4 shows the effect on LCOE when subsidies are included for the parametric study of an ISCC, PV, and CSP plants. We also calculated the subsidized LCOE for PV and CSP plants using the same methods and found that the mid-value was $110/MWh and $130/MWh, respectively.

Table 2-4: LCOE for Solar Portion of an ISCC Power Plant in Phoenix, AZ
(Unsubsidized/Subsidized)

| | | Average Wholesale Price of Electricity [$/MWh] | | | | | |
|---|---|---|---|---|---|---|---|
| | | $ 35 | $ 45 | $ 55 | $ 65 | $ 75 | $ 85 |
| Price Of Gas [$/MCF] | 2 | **$170** / 120 | **$170** / 120 | **$170** / 120 | **$170** / 120 | **$170** / 120 | **$170** / 120 |
| | 4 | $190 / 140 | **$170** / 130 | **$170** / 120 | **$170** / 120 | **$170** / 120 | **$170** / 120 |
| | 6 | $500 / 370 | $240 / 170 | **$180** / 130 | **$170** / 130 | **$170** / 120 | **$170** / 120 |
| | 8 | $2,000 + | $370 / 400 | $270 / 200 | $200 / 150 | **$180** / 130 | **$170** / 130 |
| | 10 | $3,000 + | $1,800 + | $560 / 410 | $310 / 230 | $220 / 160 | $190 / 140 |
| | 12 | $3,800 + | $3,000 + | $1,600 + | $590 / 430 | $330 / 250 | $250 / 230 |

Note: Bold font signifies a lower LCOE for the solar portion of the ISCC plant than for PV ($190/MWh) and stand-alone CSP plants ($210/MWh). All subsidized scenarios from the parametric study show the solar portion of the ISCC plant is more expensive than PV ($110/MWh) but not necessarily stand-alone CSP plants ($130/MWh).

A lower gas price and a higher electricity price reduces the levelized cost of electricity for the solar portion of the ISCC plant because it allows the capacity factor to increase. Table 2-4 shows that under the market conditions that a NGCC power plant would be built, the unsubsidized LCOE of the solar portion of solar energy is less than PV ($190/MWh) or CSP ($210/MWh).

Federal subsidies change the balance of which solar technology is least expensive to local governments: PV is slightly less expensive than ISCC because the investment tax credit and accelerated depreciation favor the more capital intensive technology. Additionally, PV requires less time to construct. Therefore, the investment tax credit, which is higher for PV than for ISCC, can be claimed earlier when the plant is operational.

**Effect of Location on ISCC Power Plant Economics**

CSP technologies can harness only beam radiation, also known as direct normal insolation (DNI). Sunlight must be reflected in order to be concentrated onto a focal point, and only radiation that comes from the same angle can be manipulated this way. Non-concentrating PV technologies are flat plate absorbers that can convert both DNI and diffuse radiation into electricity. For this reason, PV plants enhance their competitiveness relative to concentrating solar technologies in areas that experience more cloudy weather.

Figure 2-33 shows the effect of varying solar resources on the cost of the solar portion of an ISCC plant or a PV plant.
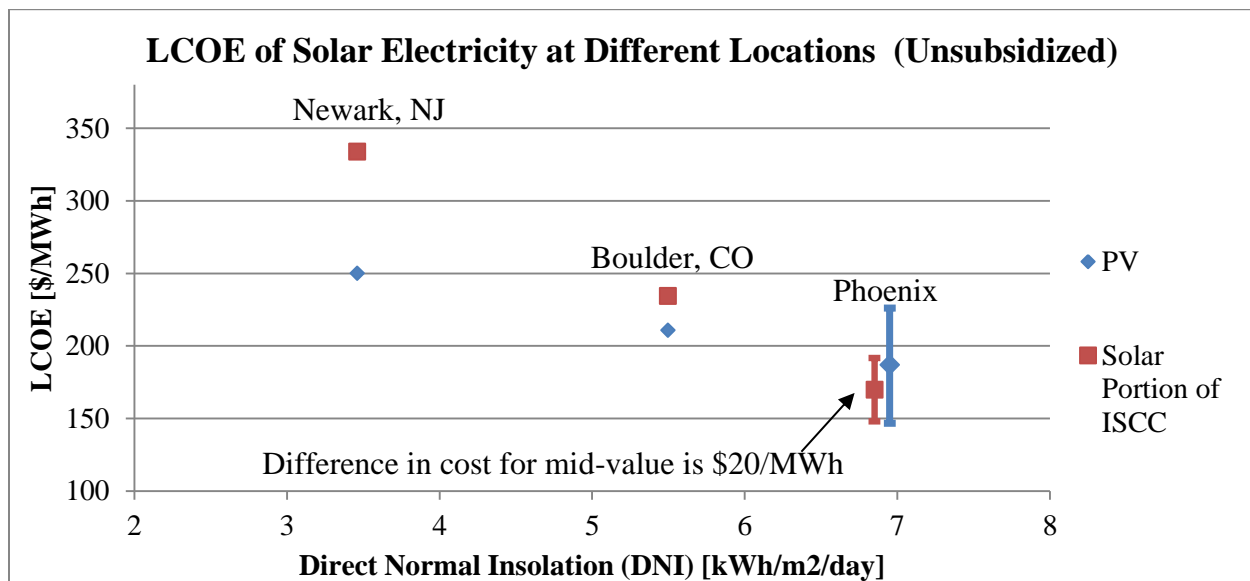


Figure 2-3: Effect of solar resource on the LCOE of PV and the solar portion of the ISCC plant. For Phoenix, we added the uncertainty of capital costs and maintenance costs as described in Table 2-4. For all ISCC data points, we assumed a gas price of $5/MCF and an average electricity price of $65/MWh. It should also be noted that solar plants for Newark, and Boulder, given their lower quality solar resources, would be designed in a way that would slightly lower the cost of electricity compared to what we show. Nevertheless, we show the difference to emphasize that ISCC would be at a disadvantage compared to PV for sites with weak DNI.

## Net Present Value of ISCC from Private Perspective

From a private perspective, ISCC is more profitable than a traditional NGCC plant only with tax incentives and a solar renewable energy credit (SREC). Since the plant can be more profitable only with a SREC, we calculated what SREC value is needed to "break even" with a NGCC plant. Table 2-5 shows the results with the asterisks indicating scenarios where the NGCC plant's NPV is negative.

Table 2-5: SREC Needed to Have the Same NPV as an NGCC Plant (Location: Phoenix, AZ)

| | | Average Wholesale Price of Electricity [$/MWh] | | | | | |
|---|---|---|---|---|---|---|---|
| | | $ 35 | $ 45 | $ 55 | $ 65 | $ 75 | $ 85 |
| | 2 | $50 | $50 | $50 | $50 | $50 | $50 |
| | 4 | $50* | $50 | $50 | $40 | $40 | $40 |
| Price Of Gas [$/MCF] | 6 | $100* | $60* | $40 | $40 | $40 | $30 |
| | 8 | $180* | $100* | $60* | $40 | $30 | $30 |
| | 10 | $270* | $180* | $110* | $70* | $40 | $30 |
| | 12 | $380* | $280* | $190* | $120* | $70* | $40 |

Note: Asterisks indicate that the NPV of NGCC plant is negative.

The SREC needed to have the same NPV as an NGCC plant is dependent how much the solar energy increased revenue and decreased costs. With high electricity prices, the solar energy adds more revenue by increasing the capacity factor. In cases of high gas prices, the solar energy decreases more fuel costs. However, high gas prices may disallow the plant from running at the time solar resources are available, and sometimes increase the SREC needed to break even.

SREC markets have been set up in many of the states that have solar set-asides in their RPS. However, Nevada does not offer such a market [32]. The price of SRECs currently varies considerably and not all can be transferred across state lines. In 2011, the SREC in Pennsylvania was in the $10 to $20 per MWh range while the SREC in New Jersey varied from $166 to $670 per MWh [33]. Aggressive solar mandates create upward pressure on demand and increase the price of a SREC if supply is not adequate. Conversely, some markets are oversupplied, for a variety of reasons, and the SREC price is suppressed [34].

**Cost of Mitigation (COM)**

We determine the cost of mitigating a tonne of $CO_2$ as:

$$Cost\ of\ Mitigation = \frac{\$/MWh_{(Renewable)} - \$/MWh_{(Fossil)}}{Tonnes\ CO_2/MWh_{(Fossil)} - Tonnes\ CO_2/MWh_{(Renewable)}}$$

For the COM, we assume no subsidies and a discount rate of 3%. We present the COM in two ways.

In order to attempt to be consistent with the existing literature, we assume the cost of a new coal-fired power plant and its emissions as the baseline for costs and emissions of the fossil power plant. However, given that the solar plant may feed a grid which is heavily dependent on natural gas (California), we also estimate the COM if a NGCC plant was off-set. Details of cost and carbon intensity of fossil fuel sources are available in the supporting information on page 45.

Table 2-6: Cost of Mitigation for Solar Portion of ISCC Plant in Phoenix, AZ
(If coal is off set / If NGCC if off set) [$/tonne $CO_2$ avoided]

| | | Average Wholesale Price of Electricity [$/MWh] | | | | | |
|---|---|---|---|---|---|---|---|
| | | $ 35 | $ 45 | $ 55 | $ 65 | $ 75 | $ 85 |
| | 2 | **$140 / 280** | **$130 / 280** | **$130 / 280** | **$130 / 280** | **$130 / 280** | **$130 / 280** |
| | 4 | $170 / 330 | **$140 / 290** | **$140 / 290** | **$140 / 280** | **$130 / 280** | **$130 / 280** |
| Price Of Gas [$/MCF] | 6 | $530 / 940 | $220 / 420 | **$150 / 310** | **$140 / 290** | **$140 / 290** | **$140 / 280** |
| | 8 | $2,400 + | $580 / 1000 | $260 / 490 | $170 / 340 | **$150 / 300** | **$140 / 290** |
| | 10 | $4,000 + | $2,100 + | $610 / 1100 | $300 / 560 | $200 / 390 | $160 / 320 |
| | 12 | $4,600 + | $3,600 + | $1,900 + | $640 / 1,100 | $340 / 610 | $230 / 430 |

Note: Bold font signifies a lower COM for the solar portion of the ISCC plant compared to PV and CSP. The COM for PV and CSP if coal was offset $160 and $190/tonne of $CO_2$. The COM for PV and CSP if natural gas was offset is $350 and $380/tonne of $CO_2$. For gas plants, we accounted for upstream emission by assumed the plant emitted 500g/kWh [35].

Table 2-6 shows that in situations where NGCC plants would be profitable, the cost of mitigation of the solar portion of the ISCC plant is lower than it would be for a PV power plant (80% of the cost at current gas prices).

**Cost Analysis if Including Variability, Transmission, and Other Costs**

Fossil plants are needed to dampen the variable generation from renewable plants. Lueken et al. found that PV plants have variability costs of ~$11/MWh and a CSP plants have variability costs of approximately ~$5/MWh [36]. We assume the solar portion of the ISCC has the same variability costs as a stand-alone CSP plant and recalculate the cost of mitigation (COM) with these costs added in. The COM for the solar portion of the ISCC plant did not change the values of Table 2-6 given the number of significant figures we report. We conclude

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that adding variability costs for solar technologies strengthens the case for ISCC, but does not change the "break points" of Table 2-6.

A significant cost that we have not accounted for in the cost of stand-alone power plants is transmission lines. Not enough solar plants have been built to estimate what the transmission cost of these distant generators would be. According to a LBNL meta-study, transmission lines for wind energy have had a median cost of $15/MWh [37]. In addition to the cost, permitting transmission lines are difficult, and the process is lengthy. From the Texas State Energy Conservation Office: "The greatest challenge facing the wind industry is that wind farms can be built more quickly than transmission lines. It can take a year to build a wind farm, but five to build the transmission lines needed to send power to cities" [38].

## 2.4  DISCUSSION

Fifteen states in the USA and a number of nations have mandates that require a portion of electricity be produced by solar energy. Although solar PV and CSP are the technologies most commonly used to meet these mandates, solar electricity from ISCC plants may be the most competitive way to produce electricity from solar energy in some regions. If the capacity factor of the plant is above 21%, ISCC may reduce costs relative to other solar options by ~$20/MWh. Another advantage to hybridization may be that it negates the need to build duplicate transmission lines, where permitting and construction is difficult and lengthy.

From a private developer's perspective, building an ISCC plant may increase the net present value only when solar renewable energy credits are available for ~$30 to $60 per MWh. This is true only if an investment tax credit of 30% is available as well as accelerated depreciation for the solar parts of the power plant as assumed in our model.

From a state or utility perspective in the U.S., the case for ISCC development is not clear cut. With current federal subsidies mentioned above, PV is slightly lower in cost. Therefore, ISCC development would be warranted if other local costs, such as new transmission lines or the variability of PV, are appreciable (on page 57 of the SI we show that there are negligible criteria pollutant advantages conferred on the gas plant by the ISCC portion).

From a social perspective, the cost of mitigation for all solar energy options examined in this paper are far higher than other low carbon electricity options [39] [40] [41] [42]. If solar from an ISCC plant offsets a new coal fired power plant, the cost of mitigation would be ~$130/ton of $CO_2$ (~$160 for PV and ~$190 for CSP per ton of $CO_2$). Clearly, this number would be higher if the electricity offset had a lower carbon intensity than coal. If solar from ISCC is used to offset an NGCC plant, the COM increases to ~$250/ton of $CO_2$. Likewise, the COM for PV and CSP increases to ~$350 and ~$380/ton of $CO_2$, respectively. Because the cost of mitigation is so high, it is highly unlikely that a price on carbon alone would induce solar development. Failed attempts to price carbon by the U.S. Congress were estimated to have a price of $60/tonne of $CO_2$ by 2030 [43].

Where a solar set-aside is mandated, the most cost effective solar option may be ISCC, in certain locations. Given the advantages noted above, governments should encourage the pathways necessary to allow for ISCC development: creating a permitting structure that clearly differentiates solar and fossil energy, creating a market for solar renewable energy credits, and ensuring that the market for those credits will be available for the duration of the project. We do not advocate ISCC as a cost effective means of mitigating carbon. We also note the limited number of solar MWh the ISCC would produce and the infrequency of flat land co-located with fossil fuel power plants in the Southwest U.S. However, governments have shown through their

solar set-asides that they desire solar electricity. In certain locations, ISCC would be a logical, practical way to build relatively cost effective solar capacity that is one of the few renewable technologies that can be hybridized with a fossil fuel power plant.

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Chapter 2

Supporting Information:


Can Hybrid Solar-Fossil Power Plants Mitigate $CO_2$

at Lower Cost than PV or CSP?

**Electricity Price Data**

We attempted to replicate representative California electricity prices by extracting the hourly data for every node tracked by CAISO [1]. Every hour, we selected the median price of all the nodes, and then aggregated that data to make an hourly data set. This hourly data was used in conjunction with hourly solar data to construct the economic model as described above. Below, we show an example of grid price behavior and solar output by showing the averages for June 2010.

**Average Daily Profile of CAISO Grid Price and Output of Solar Field**
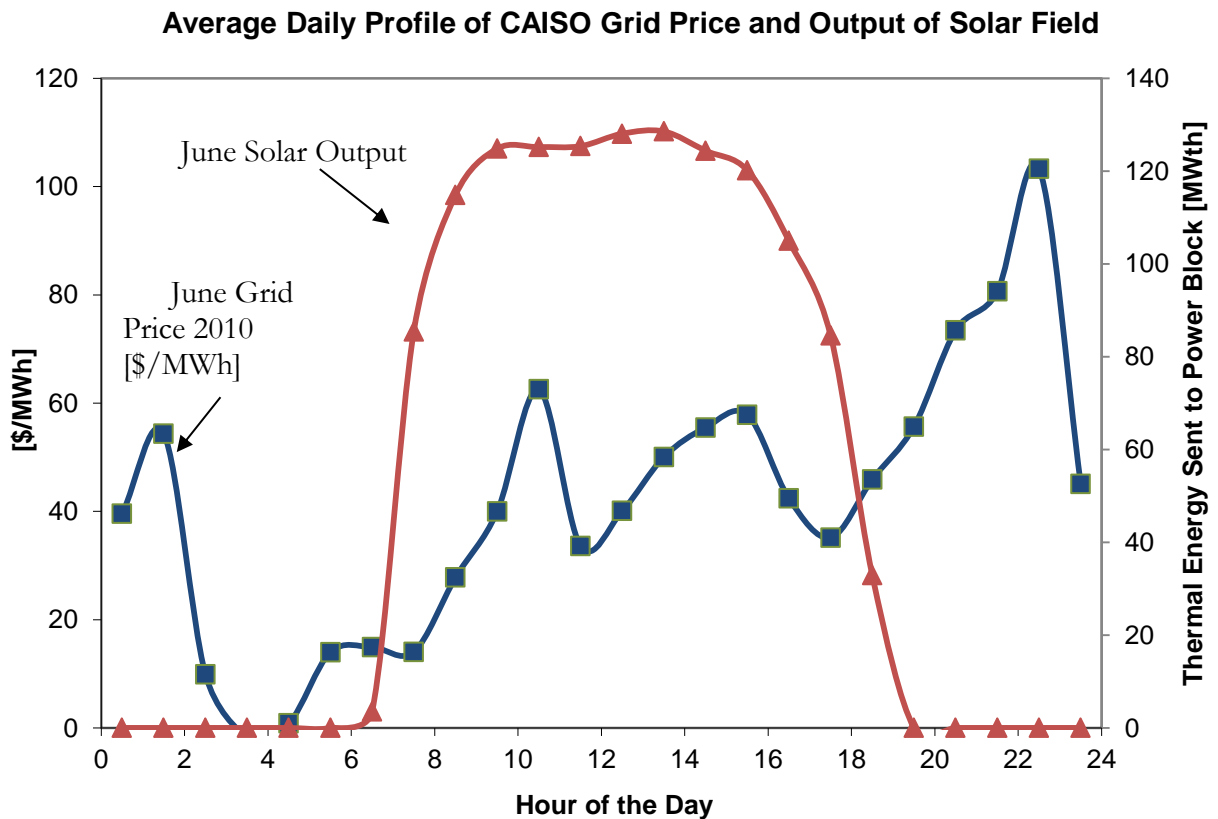


Figure 1-S1: Average daily profile of grid prices and solar field output for the month of June 2010.

Figure 1-S1 shows that the price of electricity is suppressed, due partially to hydropower, in the early summer mornings. June is the best month of the year for solar energy. We show this

month to illustrate the variability of grid prices, the dichotomy between the timing of grid prices and solar output, and the effect grid prices and gas prices have on the capacity factor of the power plant.

**Natural Gas Data**

For our parametric study, we varied the price of natural gas from $2 to $12 per MCF. For natural gas, the price seen by electric power consumers varied in California as shown in Figure 2-S2 [2].
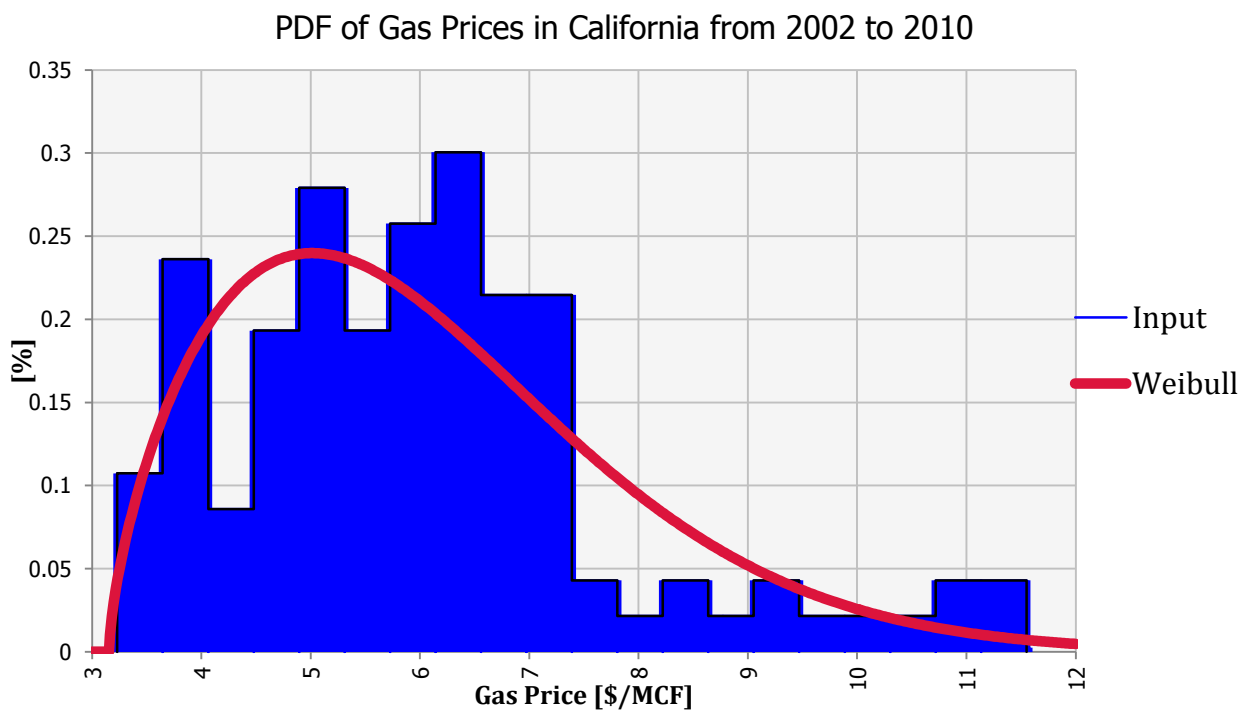
Figure 2-S2: Probability distribution function of California Natural Gas Price Sold to Electric Power Consumers (Dollars per Thousand Cubic Feet) [2] from 2002 to 2010. The observed annual average data are shown as a histogram (blue) along with a fitted Weibull distribution (red).

**Historical SREC price**

The price of solar renewable energy credits has varied considerably due to aggressive demand via solar mandates or from superfluous supply. Below is a historical look at the

variability of SREC prices in various states from Wiser et al [3]. It should be noted that the states shown are all in the U.S. Midwest or Northeast where solar resources are less abundant.
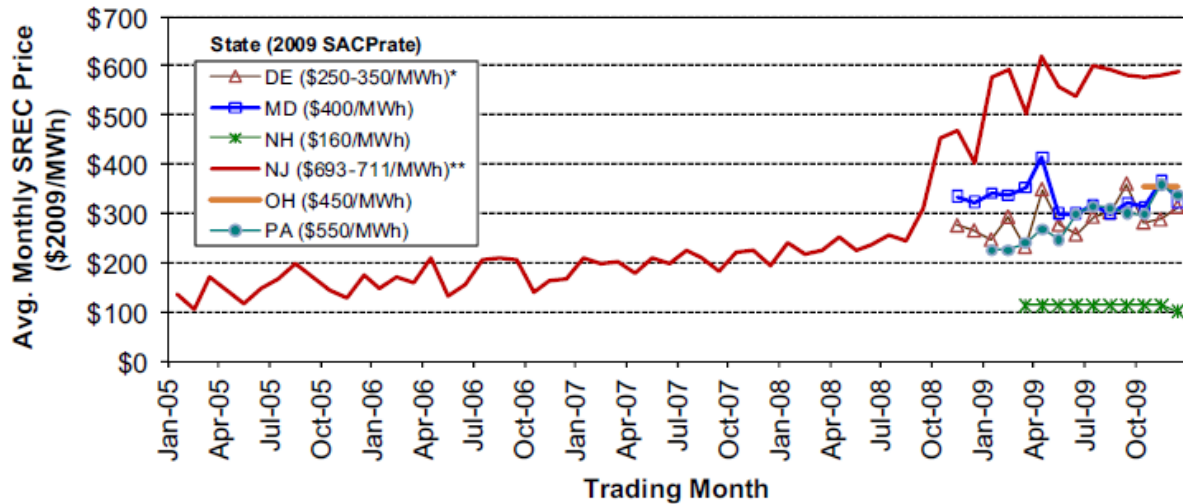


Figure 2-S3: Historical SREC spot market prices from Wiser et al. [3]

**Solar Technology and Integration Option**

A possibility to guard against the low capacity factor of the solar side is to build a dedicated solar boiler. For two retrofit projects, EPRI suggested integrating a dedicated solar boiler to increase the steam temperatures coming from the solar side of the plant so the steam turbine can run without heat generated in the HRSG [4]. We elected to not include a boiler for two reasons. First, a situation where the solar capacity factor is low is also a market situation where the NPV for an NGCC plant is negative. In situations where the NPV of a NGCC power plant is positive, the capacity factor of the solar portion of the power plant could be increased only a small amount (~1%). Second, there is significant uncertainty as to how these boilers would be operated. Boilers take hours to warm up, and the boiler would rarely be called on to run when the power plant is in "solar only" mode. Because of the uncertainty of gas prices, electricity prices, and SREC's, it could be advisable to allow room for the option to construct a

solar only boiler later in the life of the project. However, it is possible that the construction of a new source of emissions could trigger a new source review from the EPA [5].

We elected not to consider thermal energy storage for this power plant. The advantage of thermal energy storage (TES) for solar power plants is the ability to increase the utilization of the power block and run the power plant when grid prices are highest. By hybridizing solar with a NGCC, both of these goals can be accomplished with natural gas. Therefore, we elected not to examine TES quantitatively with ISCC plants.

**Solar Use Efficiency**

Above, we discussed our method for dividing solar and fossil electricity. We also discussed the fact that we needed to run the thermodynamic model at varying solar loads in order to account for variation in the solar resource. Furthermore, it is necessary to run the thermodynamic model at intermediate load to ensure that parameters were not tweaked solely to match the efficiencies and output given by the permit application to the California Energy Commission.

Since we can separate the solar and fossil electricity, we can examine how efficiently the solar thermal energy is turned into electricity. The formula for solar use efficiency is:

$$\eta_{Solar} = \frac{MWe_{Solar\&Fossil} - MWe_{FossilOnly}}{MWth_{Solar}}$$

The solar use efficiency is important because it indicates whether the ISCC plant is competitive with a stand-alone CSP power plant from an efficiency perspective. Calculating the solar use efficiency of the plant is another way of validating the thermodynamic model. The plot of the solar use efficiency curve should not contain noise and its values, as well as its shape, should match the values in the EPRI report. We have confidence in the efficiency numbers in

the EPRI report because they were generated using GateCycle software--a robust, well-known

software packaged generally trusted in industry.  A graph showing the solar use efficiency and

the MW output for varying amounts of solar energy to the power block is shown in Figure 2-S4.

**Solar Use Efficiency and Solar Electricity Generated - No Duct Firing**
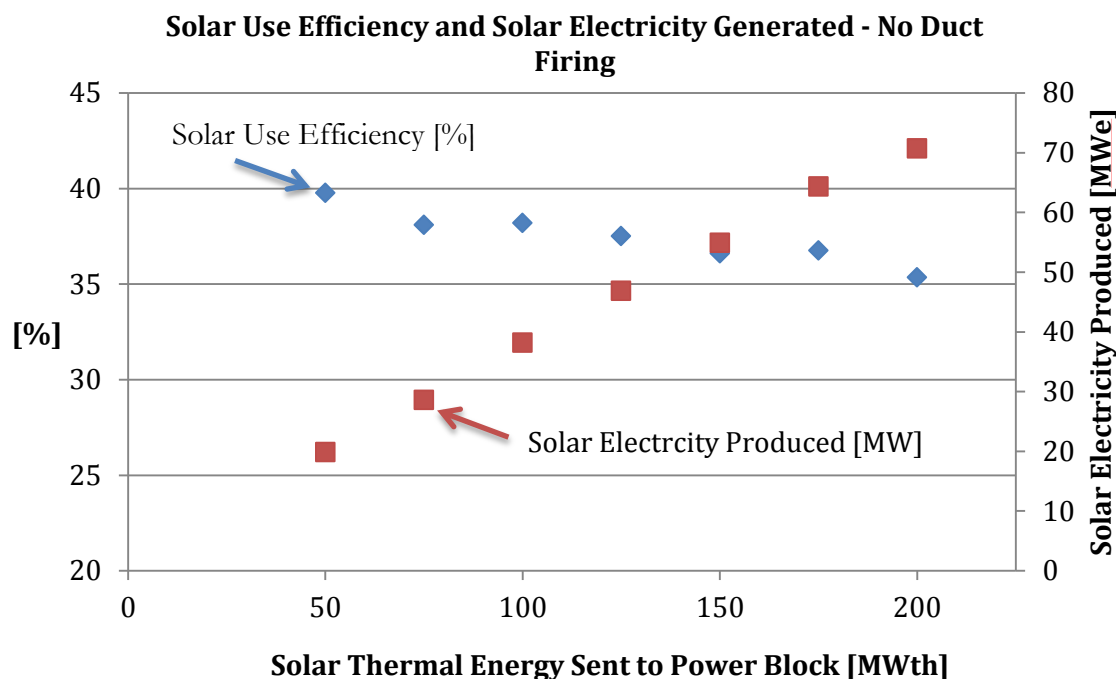
Figure 2-S4: Solar Use Efficiency and Solar Electricity Generated without Duct Firing

The solar portion of the ISCC plants have an efficiency of 35 to 40%, competitive with

stand-alone CSP plants.  Typically, CSP plants have a net efficiency in the low to mid 30's [6].

The reason the efficiency is so low is because the heat transfer fluid is limited to $750^0$F [7]

whereas modern fossil power plants operate above $1000^0$F.  As the influence of the solar energy

increases, the solar use efficiency diminishes (Figure 2-S4).  This is due to the relatively lower

temperature steam that is sent to the high pressure steam turbine as a result of mixing with a

lower temperature steam produced by solar energy.  EPRI also found the same general shape

when it calculated the solar use efficiency as well as similar solar use efficiency numbers.

**Size Limitation of Solar Energy in ISCC Plant**

The design of our ISCC plant utilizes so-called "off the shelf" NGCC components. Therefore, solar penetration is limited when parabolic troughs are used. As the influence of solar heat increases, the temperature leaving the HRSG is lowered. In the case of our thermodynamic model, keeping the pressure as directed by the CEC heat balances, the quality of the steam drops to a lower threshold (steam quality below ~0.9) at about 75 MW of solar electricity. This problem could potentially be mitigated by re-designing the HRSG or by using a solar technology that reaches a higher temperature (e.g. power tower). It is not clear whether these re-designs would enhance economic competitiveness, and the uncertainty of modeling and estimating the cost of a re-designed plant lead us to follow the Victorville 2 Hybrid Power Plant application for certification and EPRI's lead and use a standard NGCC design. We note that the solar capacity of an ISCC plant is limited. The EPRI reports, our thermodynamic model, and the parabolic trough ISCC developments indicate an upper limit of around ~15% of the capacity of a standard NGCC plant.

**Assumptions for Cost of Mitigation Calculations**

One issue that arises when calculating the cost of mitigation is setting the baseline for what type of energy production is mitigated. In other words, what type of energy should we assume is offset by renewable energy? We analyzed both coal and natural gas as the baseline. Even though coal is less prevalent in California, we chose to present the result if the solar electricity offset a coal fired power plant because it appears to be used by previous work and would set a lower bound for our analysis [8] [9]. Offsetting a new coal fired power plant, with its high carbon emissions and relatively high capital costs, minimizes the cost of mitigation (COM). We assumed the capital costs for the new coal fired power plant to be $3900/kW, the plant life to be 30 years, the capacity factor to be 85%, and the net efficiency to be 34.4% (HHV)

[10] [11]. With a discount rate of 3%, the LCOE was $56/MWh with an emission rate of 830 g-$CO_2$/kWh. For natural gas, we assumed capital costs of $1000/kW, the plant life to be 30 years, and used our economic and thermodynamic model to find the capacity factor and net efficiency which were 81% and 48% (HHV), respectively. The LCOE for for NGCC was dependent on the capacity factor, which was dependent on the price of gas. $CO_2$ emissions for the NGCC plant were assumed to be 500 g-$CO_2$/kWh, including upstream emissions [12]. On the solar side, the emissions of a solar power plant is assumed to be 13 g-$CO_2$/kWh for CSP [13] and 34 g-$CO_2$/kWh for PV [14] [8].

Suppose we assume that a "typical" kWh consumed in CA emits 410g-$CO_2$/kWh and costs $65 per the wholesale numbers above [15]. In this situation, we estimate the COM to be $180/ton of $CO_2$ offset for the solar portion of an ISCC plant  The average carbon intensity of a kWh consumed in CA was 480g-$CO_2$/kWh whereas the average carbon intensity of a kWh produced in CA was 300g-$CO_2$/kWh [15]. If solar energy is used to offset a typical kWh consumed in CA, the COM for PV and CSP increases to ~$230 and ~$260/ton of $CO_2$, respectively.

**Factors That May Change the Results of our Analysis:**

For this analysis, we model a typical solar power generator for ISCC, PV, and CSP plants, and assess *generally* whether ISCC off-sets carbon emissions more cost effectively than other solar technologies. These results are valid only for the assumptions ascribed above and cannot be replicated for all situations. In any solar power development, a myriad of issues affect the competitiveness of the plant.

- **Solar Resource:** No one metric can measure the strength of a solar resource. Average Direct Normal Insolation is the best indicator for CSP plants, but is not always the best

indicator for PV plants since they may use diffuse radiation as well. Warmer temperatures negatively affect the efficiency of PV panels. The latitude of the site may affect how the Sun is positioned in the sky and alter incidence angle between the solar rays and the solar absorbing technology. Even the timing solar resources can affect the profitability of a plant if clouds are present when grid prices are highest—as is the case with the monsoon season in Yuma, AZ in late summer months.

- **Transmission Lines:** Transmission lines cost ~$1 - $5 million per mile. Building extensive transmission lines from rural, sunny areas to populated areas is also relatively difficult to permit. Transmission line costs are not included in our analysis.

- **Ecological Sensitivity:** The CEC ruled that Tessera Solar pay $50M for mitigation costs for the ecological damage (e.g. damage to the Desert Tortoise) of their Calico Solar project [16]. One of the reasons the Victorville 2 Hybrid Power Plant that we extracted heat balances from was not constructed was the ecological mitigation costs associated with the Mojave Ground Squirrel [17].

- **Water:** It is becoming more difficult to obtain cooling water for thermal power projects, and cooling water allows plants to run more efficiently. A dry cooled condenser is also more expensive than a wet cooled one. We assumed wet cooling for our project.

- **Topography:** We assumed flat land with less than 3% gradient. Uneven topography favors PV, as parabolic troughs are 150m long and must lay perfectly flat. Quite often easements run through sites, and, depending on the angle, may negatively alter the design of a plant's layout if they cannot be re-routed.

- **Pollution:** $SO_2$ reflects and redirects solar radiation which is detrimental to CSP plants. After the Mt. Pinatubo eruption, solar output at SEGS dropped significantly [18].

Volcanic eruptions of this scale happen once or twice a century. It is also conceivable that solar radiation management geoengineering may in the future cause a 1-2% decrease in insolation [19].

- **Market:** Clearly, the price of electricity is indicative of the profitability of a plant, but the timing of grid prices is especially important to solar given the dependence on a non-dispatchable source of fuel. We assumed the timing of price fluctuations to stay the same for the duration of the project. However, with changing weather and demand for electricity, the timing for higher or lower electricity prices may change.

**Thermodynamic Model: Overview**

The basis of our thermodynamic model is the three heat balance diagrams given to the CEC in the Victorville 2 Solar Hybrid Power Plant Project application for certification. While much more information could be given from the heat balances, using some standard assumptions, enough information is given to build a robust thermodynamic model. We used MATLAB with the Cantera software package to perform the modeling [20]. Cantera looks up thermodynamic properties (i.e. entropy, enthalpy, pressure, steam quality, etc.) when given two thermodynamic properties. The open source Cantera package was developed by Professor Dave Goodwin at the California Institute of Technology.

Several items needed to be modeled to construct a heat balance: two gas turbines, three steam turbines, three pumps, 17 heat exchangers in the HRSG, condensers, and a solar steam generator. The most challenging part of constructing the model was the HRSG. Given the number of heat exchangers in the HRSG and the fact that heat exchange is dependent on the temperatures entering the heat exchanger, a miscalculation in one heat exchanger disallows all subsequent heat exchangers to be modeled correctly. We verified our model of the heat

exchangers by comparing the modeled temperatures and pressures coming out of the HRSG to what was given in the CEC permit application [21]. After we successfully modeled the heat exchangers, we were able to make assumptions (described below) about the remaining items mentioned above and match the efficiencies and MW output of the power plant.

**Thermodynamic Model: Heat Recovery Steam Generator (HRSG)**

To model the heat exchangers of the HRSG, we must find the size of each heat exchanger. To do this, we used the Effectiveness-NTU method. For counter flow heat exchangers, the maximum amount of heat that could be transferred is:

$$\dot{Q}_{hx,max} = C_{min}(T_{h,in} - T_{c,in}) \text{ (Equation S1)}$$

$C_{min}$ is whichever product of the mass flow and the heat capacity, of either side of the heat exchanger, is smaller. The actual heat exchange is the effectiveness, $\varepsilon$, multiplied by $Q_{max}$ above. From the heat balance diagram, we know the temperature, pressure, and mass flow entering and leaving almost every heat exchanger. Using Cantera software, we can find the heat capacities of the steam or gas from the heat balance diagram. Since we know the amount of heat actually exchanged and how much could have been, we can calculate the effectiveness, $\varepsilon$, of the heat exchange.

Using $\varepsilon$, we may now find the size of the heat exchanger using the equation below. We assume a shell and tube heat exchanger relationship. The equation to find the size of the heat exchanger, $UA_s$, is below:

$$NTU = -\frac{1}{\sqrt{1+c^2}} \ln\left(\frac{\frac{2}{\varepsilon}-1-c-\sqrt{1+c^2}}{\frac{2}{\varepsilon}-1-c+\sqrt{1+c^2}}\right) \text{ (Equation S2)}$$

Where $NTU = UA_s/C_{min}$ and $c = C_{min}/C_{max}$. Once we have the $UA_s$ number of each heat exchanger, we can "go forward" so to speak and actually calculate what the heat exchange would be given what is entering the heat exchanger.

Given the UA$_s$, finding the effectiveness, $\varepsilon$, of each heat exchange can be calculated using the equation below:

$$\varepsilon = 2\left(1 + c + \sqrt{1 + c^2}\ \frac{1+\exp\left(-NTU\sqrt{1+c^2}\right)}{1-\exp\left(-NTU\sqrt{1+c^2}\right)}\right) \text{ (Equation S3)}$$

After the effectiveness of the heat exchange is found, we can calculate what enters or exits the heat exchange if we know what is either entering or exiting the heat exchanger on both sides.

The first heat exchanger we modeled was the last heat exchanger before the gas exited the HRSG. Because the exiting flue gas properties are given, we have a rough estimate of the temperature, pressure, and mass flow rate of the gas exiting the heat exchanger. We also know the pressure and temperature of the water entering the heat exchanger from the condenser from the heat balance. Given what we know and what we can calculate from the equations above, we can find the temperature of the gas entering the heat exchanger. We assume the heat exchange on each side of the equation to be $\dot{m}C_p\Delta\text{T}$, and rearrange Equation S1 to form Equation S4 below:

$$T_{gas,in} = \frac{-T_{gas,out}C_{p,gas}\dot{m}_{gas} + \varepsilon C_{min}T_{steam,in}}{\varepsilon C_{min} - C_{p,gas}\dot{m}_{gas}} \text{ (Equation S4)}$$

Since we know the temperature of the gas entering the heat exchanger, we can calculate the amount of heat exchanged. Using the amount of heat exchanged, we can find the steam conditions leaving the heat exchanger.

After we found the steam conditions leaving the heat first exchanger and flue gas condition entering the first heat exchanger, we can repeat the method until for every heat exchanger until we find the steam temperatures exiting the HRSG and the gas temperatures entering the HRSG. The only exception is for the evaporators in the HRSG. However, we know the quality of the steam leaving an evaporator is one. For each evaporator, after finding the

amount of heat exchanged on the steam side, we can calculate the heat exchanged on the gas side

and stay consistent with the energy balance.

**Thermodynamic Model: Radiation in the HRSG**

We found the size of each heat exchanger, $UA_s$, by using the base load heat balance

diagram.  Once the sizes of the heat exchangers were found, we could run the model "forward"

to check the results of the calibration.  If each heat exchanger were being modeled correctly, the

resulting gas entering the HRSG should be around 1125 $^0$F in all cases and the temperature of the

steam entering the high pressure steam turbine 1050 $^0$F (or 920 $^0$F if the solar field is active).

Realistic results could not be attained running the model "forward" unless radiation was

taken into account.  General Electric's website states that "GateCycle (and most other

commercial heat balance software packages) use the 'Effectiveness – NTU' method…[which]

does not account for radiative heat transfer that is present under heavy supplemental firing

conditions" [22].  We are not sure whether the heat balances given to us had radiation taken into

account, but in order to achieve realistic results, we did incorporate radiation.

To add radiation to our model, we assumed the radiative transfer followed Equation S5

below.

$$\dot{Q}_{rad} = \varepsilon A_{s(T_s{}^4 - T_{surr}{}^4)} \text{ (Equation S5)}$$

We do not know the emissivity, $\varepsilon$, of this equation or the area of heat transfer, $A_s$.  Since

these are both linear, we combined them as one constant, $\varepsilon A_s$.  To find the constant, first we

assumed that the area of radiative heat transfer is commensurate with the size of each heat

exchanger found above.  Without radiation, we found that the temperature of the flue gas

entering the HRSG would have to be extraordinarily high in order to heat the steam temperatures

to $1050^0$F.  Our program adds heat radiative heat transfer area, increasing the amount of heat transfer via radiation, until the flue gas reaches the temperature of $1125^0$F.

For each individual heat exchanger, we have two mechanisms to exchange heat: traditional heat exchanger and radiation.  Simply adding these heat transfer mechanisms together yield unrealistic results, so we had to adjust the model again.  Essentially, if some heat is being added to the steam via radiation, then not as much heat is needed from the flue gas, so the flue gas's temperature should not change as much.

To reconcile this problem, we set up a loop within MATLAB.   First, we assumed no heat transfer from radiation and assumed all heat transfer would occur because of convection from the heat exchanger.  As described above, this would produce some initial guesses where the change in temperature on the gas side would be enormous.  Then, we used the temperature difference to estimate the amount of radiative heat transfer.  If we subtract the radiative heat transfer from the convective heat transfer, the temperature difference on the gas side is very small.  Repeating the loop leads to a radiative heat transfer guess that is very small.  We repeat this loop until the gas temperature as predicted with convective heat transfer and the gas temperature as predicted with radiation converge.

**Thermodynamic Model: Bringing it All Together**

To summarize, we used the base-load heat balance diagram to find the heat exchanger sizes.  We used the above radiation technique to adjust the size of the radiative heat transfer until the flue gas entering the HRSG was the same as given in the heat balance diagrams.  To ensure that assumptions were not only suitable for base load case, the model was run "forward" using the $UA_s$ numbers and radiation heat transfer areas with the duct firing case and the duct firing

with solar case. Below in Figure 2-S5, we show the temperatures within the HRSG the results from our model.

**Temperatures of Gas and Steam States in the HRSG (Baseload)**
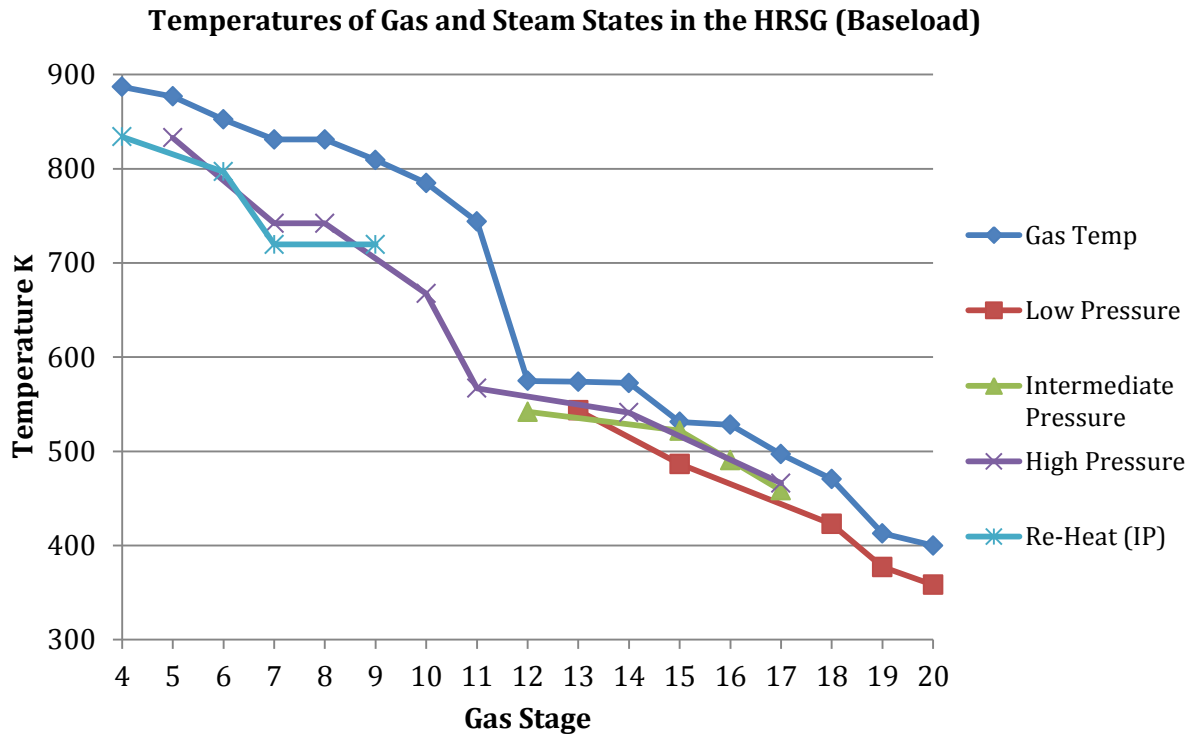


Figure 2-S5: Temperatures of Gas and Steam States in the HRSG.

Once we were able to get the HRSG to model as shown by the heat balance diagrams given to the CEC, we were able to use some relatively simple assumptions for the way the rest of the cycle worked. For the gas turbine, we simply assumed it would run at the efficiency and mass flow rate as given in the heat balance. No other modeling is necessary for the natural gas turbine, because we assume that it always runs at steady state. We assumed that the steam turbines and pumps operated with an isentropic efficiency of 91% and 85%, respectively. For the condenser, we assumed wet cooling and that the cooling temperature of the water stayed constant. For the solar steam generator, we assumed that the mass flow of the steam going to the solar steam generator was controlled such that a constant steam temperature exited the solar steam generator.

**Solar Models**

To model the solar thermal energy sent to the power block, we utilized National Renewable Energy Laboratory's (NREL) Solar Advisor Model (SAM). The model was constructed based on experience and data from SEGS power plants. NREL is in the unique position to act as neutral tester of solar equipment, and this information is used for modeling. We assisted Lueken et. al. [23] in modeling the data collected from Nevada Solar One and found that SAM accurately predicted how much annual electricity was actually produced.

Given our knowledge of SAM, modeling the energy sent to the power block was feasible. SAM software can be downloaded for free and is uploaded with default options that are considered typical for a CSP power plant. For the CSP power plant, the only inputs we needed to toggle were the solar multiple, thermal energy storage (and parasitic load for thermal energy storage), and the so called "max over design operation". The default size of a CSP project in SAM is 100 MW, but since our comparisons are on a MWh basis, the size of the project does not need to be changed.

The "max over design operation" is a steam turbine rating issue. Theoretically, some steam turbines are rated at say 125 MW, but with a 1.15 "max over design operation", the default in SAM, the real capacity of the turbine is 144 MW. We assume that a steam turbine with a capacity of 125 MW means it cannot produce more than 125 MW. When Lueken et. al. modeled the NSO data, this was one adjustment needed in order for the numbers to align [23]. Clearly, we don't have any thermal energy storage in this simulation so it, along with the associated parasitic load, may be eliminated.

The solar multiple is an important, unsettled value that requires explanation. It is defined as the thermal capability of the solar field at design conditions (1000 W/m$^2$, 25$^0$C ambient

temperature) divided by the thermal capability of the power block. Given the rare frequency of design conditions, it is economically advantageous to oversize the solar field in order to increase the utilization of the power block. Since the solar field is oversized, sometimes solar energy is wasted, and this is done by turning down the mirrors. A reasonable value used in industry for a stand-alone CSP power plant in Phoenix would be a solar multiple in the ~1.35 range. Essentially, the solar multiple is a balance to ensure that the utilization of the power block and solar field maximizes the economic competitiveness of the plant. We used a solar multiple of 1.35 for our simulation of a stand-alone CSP plant. This number may be much higher if storage is available or if the solar resource is weak.

There is also a solar multiple for our ISCC simulation—1.1. This time, the definition is in regards to the non-solar solar field components: pumps, pipes, and the solar steam generator. It is much lower for ISCC plant because the utilization of the solar steam generator is not as important because the solar steam generator costs far less than an entire power block would. This number is not based on literature or any optimization studies, but on a recommendation [24]. For the ISCC plant, we wish to calculate only the amount of energy sent to power block. Since SAM disaggregates where the energy is flowing within the CSP plant, it is easy to extract the amount of energy sent to the power block. A sample output from SAM is shown in Figure 2-S6 below:
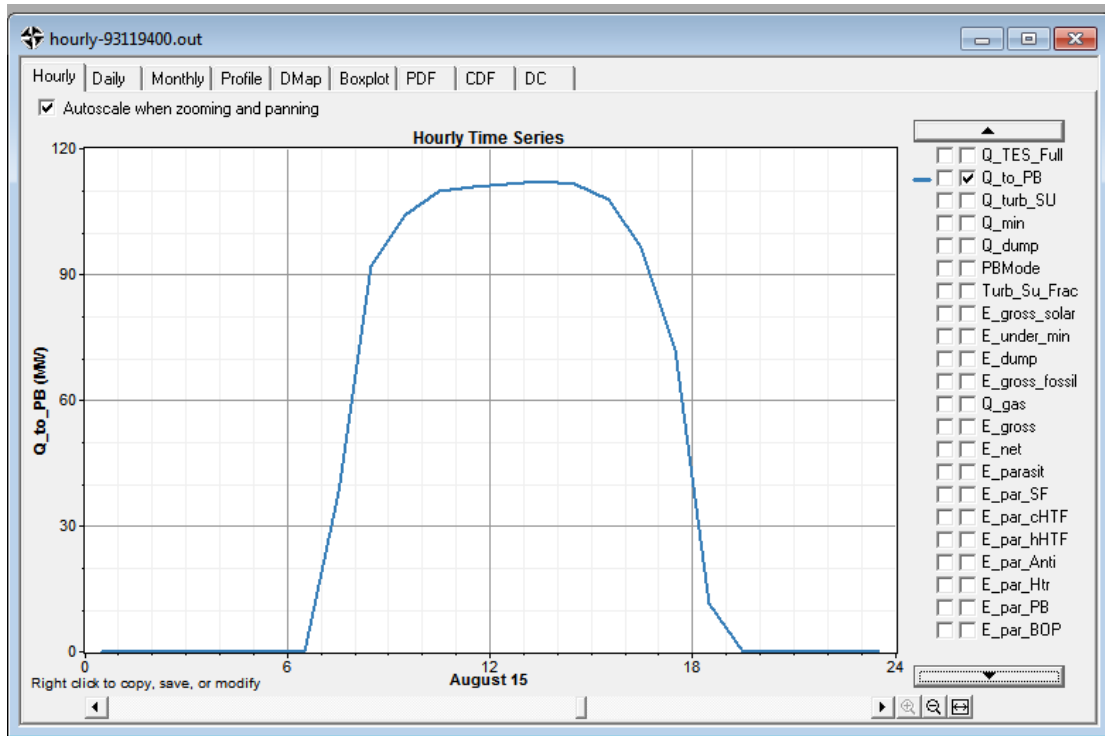
Figure 2-S6: Output from SAM for an example 24 hour period. In the right column, "Q_to_PB" is checked and is the energy sent to the power block used for our ISCC simulations.

To model the PV power plant, SAM was used as well. We assumed First Solar Panels and no tracking. We used the default NREL assumptions but changed the tilt of the panels to $30^0$. The rule of thumb in the solar industry is that the tilt of the solar panel should be about the latitude of the site. We ease the tilt to prevent some panel to panel shading which is present in utility scale arrays. We did not have to change the capacity of the power plant from SAM's default because we are making comparisons on a MWh basis.

To summarize, SAM was used to model the solar output for all technologies. We did not perform full blown economic optimizations for the designs of the plants but used best practices appropriate for the desert climate garnered from industry. Since these practices are only generally suitable for the Southwest U.S., we show how profoundly location can change our economics in Figure 2-3 of the main paper. We also warn that solar plants designed with weaker solar resources would be designed differently.

**COM Calculations if Criterion Pollutants Credits are Included**

It may be argued that our COM calculations are incomplete because we have not added

credits for the $NO_x$, $SO_x$, and Mercury pollution abated. We chose not to include these in our

analysis because there is a considerable amount of uncertainty. For instance, see Katzenstein et

al. where they note that the variability of wind causes some $NO_x$ emissions from the ramping of

simple cycle natural gas turbines [25] . Additionally, including these credits requires a

quantifiable monetary credit which may be considered arbitrary. To examine the scale of the

difference when credits for these pollutants are added, we assumed the following:

Table 2-S1: Assumptions for Pollutant Credits Allocated [9]

| Criterion Pollutant | Emission Rate (Coal Power Plant) [Pounds/MWh] | Credit per Pound of Emission | Credit Per MWh [$/MWh] |
|---|---|---|---|
| $SO_x$ | 11.4 | $ 0.44 | $ 5.02 |
| $NO_x$ | 5.3 | $ 0.38 | $ 1.99 |
| Mercury (Hg) | $7.2 \times 10^{-5}$ | $ 55,000 | $ 3.96 |
| Total | | | $ 11 |

Using the unsubsidized LCOE of $190/MWh from PV from the body of the paper above, and

giving it the $11/MWh credit for criterion pollutants assumed to be offset, we arrive at a COM of

$150/tonne of $CO_2$.

**Transmission Cost Estimate for Solar**

It is difficult to estimate the expected transmission costs for solar because of a lack of

large scale solar power plants built. One large scale transmission line slated for solar is the 1,000

MW Sunrise PowerLink Transmission line in Southern California that costs two billion dollars.

However, the utility, PG&E, does not guarantee that the transmission line will be used for

renewable energy. It has promised only to give preference to renewable energy, citing fear that

renewable projects intended for the area might not be constructed [26]. Since we cannot allocate

costs for that transmission line to solar electricity, we estimate the cost using the Renewable

Energy Transmission Initiative estimate for the transmission line infrastructure needed to meet

California's 33% renewable energy mandate by 2020 [27]. Assuming an annuity over 40 years

with a 6% interest rate, the transmission cost for renewables would add approximately

$10/MWh. This is in line with the estimate from Dobesova et al which estimated a cost of

$10/MWh [28].

**Levelized Cost of Electricity (LCOE) Assumptions**

We computed the levelized cost of electricity in order to assess the economic value of the

solar portion of the power plant:

$$LCOE = \frac{\sum_{Initial\ Year\ of\ Construction}^{Final\ Year\ of\ Project} Present\ Value\ of\ Costs}{\sum_{Initial\ Year\ of\ Construction}^{Final\ Year\ of\ Project} Present\ Value\ of\ Electricity} \text{ (Equation S6)}$$

The equation above is based on the National Academies' guidelines for estimating the levelized

cost of electricity as detailed in *America's Energy Future: Technology and Transformation* [29].

To find the present value of costs and electricity, the above equation could also be written as:

$$LCOE = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+d)^n}}{\sum_{n=0}^{N} \frac{E_n}{(1+d)^n}} \text{ (Equation S7)}$$

Where:
  $C_n$ = Cost in period n
  N = Analysis period
  D = annual discount rate
  $E_n$ = Electricity output in year n

The costs incurred are detailed in the main body of the paper. To find the LCOE, we

estimated the year in which costs and electricity are created. The amount of electricity created is

based on expected behavior of a generator maximizing marginal profits. It has been suggested

that the amount of electricity generated be based on technical capability and not market

conditions. However, we examine a range for economic conditions that encompasses the full technical capability of the solar portion of the ISCC.

We assumed that capital costs would be divided evenly over the number of years needed for construction. Capital costs, fuel costs, O&M costs, and costs of capital were included in all cost estimates regardless of perspective. Public cost estimates were assumed to have a discount rate of 3%, and the private NPV estimate assumed a discount rate of 12%.

From the social perspective, taxes, subsidies, and revenue were not included. We assumed that the cost of capital was accounted for by calculating the interest payments. We assumed that loans for capital costs would be paid in 10 years after the start of operations. We assumed debt would be paid off with an annuity payment calculated as:

$$A = P \; \frac{i}{1-(1+i)^{-n}} \; \text{(Equation S8) [30]}$$

Where:
    A = Annuity
    P = Principal
    i = interest rate
    n = loan periods in years

Interest payments were calculated by finding the interest paid on the amount of capital loaned each year.

From a local government perspective, federal subsidies are included in the LCOE because it may be considered "free money" to that local government. The investment tax credit, which is 30% of the capital costs, is assumed to be credited during the first year of operation. We calculated the difference in tax burden between standard depreciation and accelerated depreciation for the renewable portion of the plant, and the net present value of the difference was credited as a subsidy.

From a private perspective, we did not calculate the levelized cost of electricity but calculated the net present value (NPV). The difference is that all taxes and subsidies are included in the private NPV estimate, and revenue is also included. We assumed a discount rate of 12%. Other economic assumptions are summarized in Table 2-S2 below.

Table 2-S2: Economic Assumptions

| | |
|---|---|
| Private Discount Rate: | 12% |
| Social Discount Rate | 3% |
| Equity Ratio | 65% |
| Fossil Portion Depreciation | Straight line over lifetime of plant |
| Renewable Portion Depreciation | Accelerated over 5 years |
| Federal Tax Rate | 34% |
| State Tax Rate | 4.2% |
| Interest Rate | 5.8% |
| Investment Tax Credit (Renewable Portion | 30% |
| Location of Power Plant unless noted otherwise | Phoenix, Arizona, U.S. |

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# Chapter 3:  THE EXTERNAL COSTS AND BENEFITS OF WIND ENERGY: A CASE STUDY IN THE PJM INTERCONNECTION

This chapter was co-authored with Roger Lueken and Jay Apt.

**ABSTRACT**

Large deployments of wind create external costs and benefits that are not fully captured in power purchase agreements.  External costs are due to the inherent variability and unpredictability of wind power and its negative effects on the local environment.  Reduced greenhouse gases and criteria pollutants from fossil plants are external benefits.  We investigate the external costs and benefits of wind in the PJM Interconnection for two scenarios: a 2012 scenario with 1.5% of energy from wind, and a high wind scenario with 20% of energy from wind.  We find that external costs are uncertain but significant when compared to levelized PPA prices.  The expected value of external costs is $23/MWh in both scenarios. Pollution reduction benefits are very uncertain but exceed external costs with high probability.  For the low wind scenario, expected pollution reduction benefits exceed expected external costs by $97/MWh, with a 90% confidence range of $40/MWh - $160/MWh.  In the high wind scenario, expected pollution reduction benefits exceed expected external costs by $114/MWh, with a 90% confidence range of $50/MWh - $190/MWh.   Pollution reduction benefits may decrease in the future if criteria pollutant emission rates from PJM fossil plants continue to drop. If EPA cross-state air pollution regulations result in binding emission caps, policies that incentivize wind will not reduce criteria pollutant emissions and wind's external costs may exceed its external benefits.  If caps bind at anticipated permit prices, state renewable portfolio standards may have fewer benefits than if they do not bind.

## 3.1 INTRODUCTION

In the United States, a variety of government subsidies and falling capital costs have resulted in nationwide deployments of more than 60 GW of wind capacity since 2002 [1]. However, low wholesale electricity prices, driven by falling demand and the expansion of domestic gas production, have eroded support for wind subsidies. The federal production tax credit expired at the end of 2013 [2] and several state legislatures have considered repealing or limiting state renewable portfolio standards [3]. This debate is underpinned by the following question: are policies incentivizing wind justified?

Wind developers typically sign long-term power purchase agreements (PPAs) to sell the energy produced by wind projects. The price of a PPA is determined by the private costs of developing a wind project, which include turbine costs, installed project costs, transmission connection costs, taxes, subsidies, operations and maintenance costs, and other development costs. PPA prices are also influenced by market characteristics, such as avoided costs on wholesale markets, and do not directly represent project costs [1].

Levelized PPA prices can be useful for comparing the competitiveness of wind to other electricity technologies. However, levelized PPA prices are not a useful metric for fully accounting for the costs and benefits of wind power relative to other electricity technologies [1]. Evaluating wind's effect on overall social welfare requires a full accounting of private costs and the costs and benefits that accrue to entities other than the PPA holder. PPA prices "do not fully reflect integration, resource adequacy, or transmission costs" [1]. These external costs, along with wind's environmental costs and benefits, accrue to third parties.

Wind power has several characteristics that create external costs and benefits (ECBs) that are different than those of traditional power plants. Managing wind's inherent variability can

require operating other plants less efficiently and can require significant grid expansion and reinforcement. Wind may be harmful to ecosystems and wildlife, and may be a nuisance to local communities [4] [5] [6]. Finally, wind turbines emit no greenhouse gases (GHG) or criteria pollutants (CP), benefiting public health and the climate.

ECBs vary across different systems, and depend on system size, location, and level of wind penetration. Several studies have investigated individual ECB categories [7] [8] [9] [10] [11] [12] [13] [14]. These studies are difficult to compare, as the methods, assumptions, and systems they study vary greatly. Few studies have attempted to comprehensively measure wind's external costs and benefits. The OECD analyzes the comprehensive costs of wind for several developed countries [7], but focuses on national-level costs and excludes the benefits of wind.

In this paper, we quantify the external costs and benefits of wind power in the PJM Interconnection. Our accounting of these costs and benefits is meant to contribute to the evaluation of existing and future incentives for wind energy in PJM. We considered the major ECB categories discussed in literature (Table 3-1). We levelized the ECBs so they can be directly compared to levelized PPA prices. We analyzed average expected ECBs for two scenarios: a low wind scenario representative of PJM as it was in 2010 with 1.5% of energy from wind, and a high wind scenario with 20% of energy from wind. These two scenarios can be viewed as lower and upper bounds of wind's penetration in PJM for the foreseeable future. ECBs are highly uncertain and cannot be calculated with a high level of precision. Therefore, we did not attempt to find the marginal ECB nor the optimal level of wind deployment that satisfies the first order condition. Rather, our goal was to identify if wind's ECBs are significant, and therefore if policies to incorporate these costs and benefits into private decision making are

warranted.  Due to this inherent uncertainty, our results are presented as probability density functions.  Accounting for the full range of uncertainty is necessary for a robust evaluation of the appropriateness of current and future wind incentives.

We do not quantify the damages that wind can cause to the local environment and stakeholders.  Wind can harm biodiversity and ecosystems, cause bird and bat collisions, visual pollution, and noise pollution.  We provide a discussion of these issues, but do not quantify them as they are highly uncertain and difficult to quantify rigorously.

The participation of wind on energy and capacity markets will create second-order effects for other market participants.  Wind provides energy at very low marginal costs, offsetting more expensive generation and lowering energy prices.  Wind also provides equivalent load carrying capability, which will affect prices on the capacity market.  We do not quantify these effects in this analysis.  Doing so would require a detailed analysis of the interplay between energy and capacity markets, which is beyond the scope of this paper.  The Methods section contains a more thorough discussion of this topic.

Table 3-1 Definitions of Wind's External Cost and Benefit (ECB) Categories

| Category | Definition |
|---|---|
| **External costs** | |
| Operational costs | The cost of ensuring stable grid operations, distributed across different markets (unit commitment, load following, regulation, and reserves) |
| Grid reinforcement and expansion | The cost of expanding and reinforcing the grid to support distant and variable wind plants |
| **External benefits** | |
| Greenhouse gas reduction | The societal benefit of reducing $CO_2$ and other greenhouse gas pollutants by displacing fossil-fueled generation with wind |
| Criteria pollutant reduction | The societal benefit of reducing criteria pollutant emissions ($NO_x$, $SO_2$, particulate matter) that harm human health and the environment, by displacing fossil-fueled generation with wind |

## 3.2  METHODS

We investigated the external costs and benefits of wind in the PJM Interconnection.  We separately analyzed the six categories most discussed in literature (Table 3-1).  We analyzed these categories for PJM under a low wind scenario with 1.5% of energy from wind, as it was in 2010, and a high wind scenario with 20% of energy from wind, as is possible under the renewable portfolio standards of PJM member states [2].

Because estimates of each ECB category are uncertain, we treated wind's ECBs probabilistically with Monte Carlo simulation [15].  For each category, we estimated a lower bound, upper bound, and mode for triangular distributions in the low wind and high wind scenarios.  We then used Monte Carlo simulation to calculate the probability density function of total external costs and external benefits.

Our estimates for each category are based on existing literature and our internal modeling using a unit commitment and economic dispatch model (UCED) of the PJM Interconnection. ECB estimates are highly dependent on the makeup of the electricity grid, generator technologies, location and quality of wind resources, and fuel costs. Most importantly, estimates vary due to differences in methods among studies. By combining prior research and the present modeling with multivariate Monte Carlo analysis, we investigated a large range of possible values for each ECB category.

Our UCED, the PHORUM model, uses mixed integer linear optimization to find the least-cost combination of generators to meet load at each hour of the year [16]. The optimization considers each plant's fuel costs and variable operations and maintenance costs. PHORUM also tracks emissions from each plant. PHORUM uses 2010 data to simulate PJM's day-ahead energy market. We updated the emission rates of $CO_2$, $NO_X$, and $SO_2$ for each plant to 2012 levels (see Pollution reduction benefits section). We used PHORUM to estimate operational costs and pollution reductions because we found no other study or model that allowed us to simulate system-level costs and emissions at different levels of wind penetration in PJM. The high wind scenario, with 20% of energy from wind, used data from the Eastern Wind Integration and Transmission Study (EWITS) to characterize likely locations for new wind plants in PJM states [8].

**Operational costs**

Operational costs are the costs of maintaining grid stability by continuously balancing total generation with total load, given the variability and unpredictability of renewable energy. Operational costs occur from the next 48 hours to real-time [17]. The net effect of these costs is increased prices in markets run by the independent system operator (ISO), including the energy market, regulation market, and reserve markets. Compensating for wind variability requires

ramping other generators in the system, which in turn can cause generators to operate inefficiently and increase the frequency of generator cycling. The variability of wind also leads to forecasting errors that increase reserve requirements and, when realized, may force system operators to use fast-ramping but inefficient generation instead of more cost-effective generators. Day-ahead wind forecast errors are typically 8% - 14% (RMS error) [18].

Calculating increases in operational costs requires both a statistical model of wind generation and a model of the electricity grid. Wind models use either measured or simulated wind speed data. Grid simulations vary in complexity from simple unit commitment models to more sophisticated models that capture forecast uncertainty and electrical dynamics of the grid. To isolate the costs of wind variability and unpredictability, it is common to use the 'flat-block' approach, in which a scenario with wind is compared not to a scenario without wind, but rather to a scenario in which the wind generation is constant and perfectly known [8].

Figure 3-1 shows operational cost estimates of several published studies [8] [9] [10] [11] [12] [13] [14] and our modeling with PHORUM. The studies vary in the costs they include, but generally find that unit commitment and load following costs are larger than regulation and reserve costs. The exception is Lueken et al. [14], which used historical California regulation market price data instead of simulation techniques to estimate operational costs. The high resulting costs suggest that either simulation methods may be biased to under-predict regulation costs, or that the observed California price data may be unrepresentative of areas used in simulations.

The published studies we review are for systems other than PJM. Our internal modeling with PHORUM enabled us to directly assess the effect of wind on the PJM system. Our findings are similar to those of other studies (Figure 3-1). Increases in operational costs depend on the

generation technology displaced by wind.  Our simulations show that in the low wind scenario, the generation offset by wind in PJM was 77% coal and 20% combined cycle.  For the high wind scenario, the generation offset was 91% coal and 4% combined cycle.  If gas prices were to fall and make combined cycle generation more competitive with coal, we expect that wind could be integrated more inexpensively, as the higher ramp rates and flexibility of combined cycle plants match well with the variability of wind.

The low wind scenario operational costs range from $0 - $4.3/MWh, with a mode of $1.2/MWh, and high wind scenario costs range from $1.9 - $9.7/MWh, with a mode of $4.0/MWh. For both scenarios, bounds were derived from existing literature and mode values from PHORUM simulations.
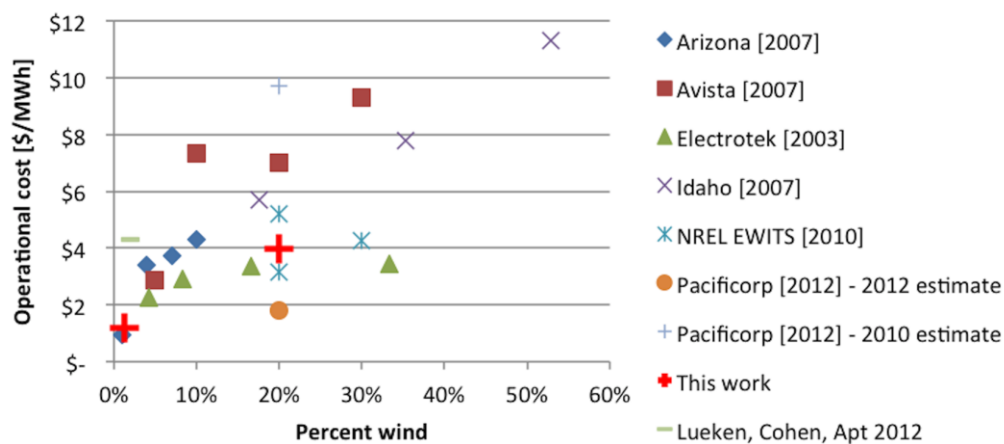


Figure 3-1 Estimate of operational integration costs from previous literature and work (2010 dollars)

**Grid reinforcement and expansion costs**

The cost of connecting electricity produced by distant and variable renewables to load is an appreciable cost for wind energy.  The allocation of these costs is also subject to extensive debate, leading FERC to issue Order No. 1000 [19].  Order No. 1000 requires local transmission providers to participate in the regional transmission planning process.  It specifically requires

transmission providers to devise cost allocation methods that, "…consider transmission needs driven by public policy requirements established by state or federal laws or regulations" [19].

FERC's order recognizes that transmission is a large impediment to wind energy development and could keep states from realizing renewable portfolio standards [20]. Transmission lines typically require far more time to develop than wind projects, and, once developed, there is a "free-rider" problem. Regions benefit from new transmission through eased transmission congestion or increased grid reliability by connecting dispatchable generators.

Fully allocating the costs and benefits of transmission that is necessary to enable wind development is beyond the scope of this study. For purposes of this research, we will follow the allocation method set by PJM in response to FERC Order No. 1000. PJM has allocated the costs to ratepayers for large transmission lines (above 345 kV) [21].

The Lawrence Berkeley National Laboratory (LBNL) reviewed a sample of 40 transmission planning studies from across the country to assess the range of costs allocated to wind for transmission [22]. The vast majority of transmission lines in the sample were above 345 kV and the majority of these costs would be socialized among ratepayers according to PJM's new transmission allocation cost method [21]. Therefore, we use the LBNL study for the external costs of transmission for wind at low penetrations of wind.

LBNL found that transmission has a median cost of $300/kW of wind capacity. We converted these numbers to a levelized cost ($/MWh of wind) assuming a 28% capacity factor for PJM wind projects [1] and a fixed charged factor of 15% as assumed by the LBNL authors. A histogram of the costs is shown below in Figure 3-2.
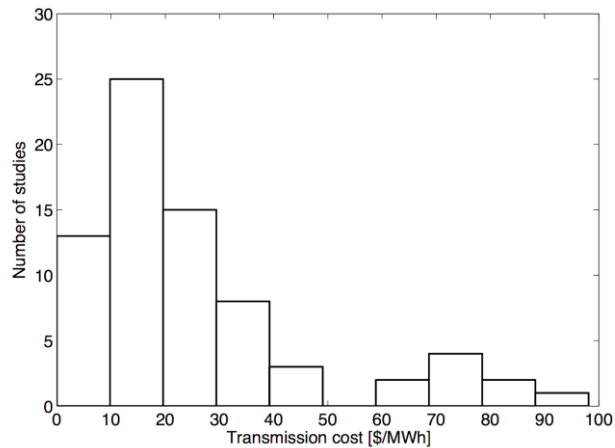
Figure 3-2. Histogram of transmission line costs from LBNL [22], assuming a wind capacity factor of 28% and fixed charge factor of 15%.

Transmission costs varied from $0/MWh to $98/MWh with a median of $18/MWh. Cost estimates at the high end are due to projects with transmission oversized for future plant development. Ignoring these projects, we assumed transmission costs range from $0/MWh - $48/MWh with a mode of $16/MWh. The study also examined the case in which costs were not allocated to fossil plants on the same transmission line. This made a small difference increasing the cost allocated to wind by $30/kW ($2/MWh). We did not include these co-benefits or costs in this analysis, but note that they may be appreciable [8] [23].

In order to realize 20% penetration of renewable energy, a significant "top-down" expansion of the transmission grid may be necessary [8]. Table 3-2 shows capital cost estimates from studies of very large transmission expansions across the country in order to incorporate high wind penetrations. Based on these studies, we assumed bounds of $4 - $35/MWh of wind for the high wind scenario, with a most likely value of $15/MWh. Transmission costs for these studies are in the range found in the LBNL report, and agree with LBNL's finding that, "Unit transmission costs of wind … do not appear to increase significantly with higher levels of wind addition" [22].

Table 3-2 Capital Costs from Various Large Transmission Studies and Calculated Levelized
Cost, assuming 28% Wind Capacity Factor and 15% Fixed Charge Factor

| Cost per kW of Wind [$/kW] | Levelized Cost Per MWh of Wind [$/MWh] | Study |
|---|---|---|
| 150 - 300 | 9 – 18 | LBNL from AEP [22] |
| 207 | 13 | NREL [8] |
| 316 | 19 | LBNL from NEMS [22] |
| 67-367 | 4 - 22 | Holttinen [24] |
| 350-570 | 21 - 35 | DOE for ERCOT [25] |
| - | 9 | Dobesova et al. [26] |

**Resource adequacy**

In this section, we discuss the resource adequacy (capacity) implications of wind. Wind

energy provides relatively little capacity during times of peak load, as computed by the metric

Equivalent Load Carrying Capability (ELCC) [27]. In PJM, wind receives an ELCC rating of

13% [27], meaning that 100 MW of nameplate wind capacity, its capacity contribution would be

rated at 13 MW.

Some researchers have quantified the cost of procuring capacity so wind generators

would have similar ELCC ratings as dispatchable generators [28]. In this research, we do not

consider this point of view because we are not comparing wind to generator options. Here, we

are examining the externalized costs not included in PPA contracts for wind so that policymakers

may make a more informed decision about whether or not to implement wind.

In the sections above, we quantified transmission and ancillary services because wind

increases the demand for these services and the costs are born by stakeholders other than the

PPA holder. The addition of wind by itself does not increase the demand for capacity [29]. On

the contrary, wind increases the supply of capacity, albeit in a relatively small amount. To first

order, the net effect of wind is increased energy and capacity supply. How the cost of energy

and capacity supplied by wind compares with the cost of energy and capacity it would displace is beyond the scope of this research.

It is worth noting that wind energy may have adverse second order effects on capacity market *prices* because it supplies a disproportionate amount of energy compared to capacity. Bids in capacity markets are driven by fixed costs less profits made in energy markets [30]. The addition of wind undercuts the profits of fossil generators in energy markets and causes them to increase their bids in capacity markets. However, these changes affect the revenue source (i.e. energy or capacity markets) for producers and not the overall social costs of capacity.

**Curtailment costs**

Curtailment occurs when wind plants intentionally reduce power output due to transmission constraints or market conditions. Wind curtailment has been reported for only six months in PJM and has been insignificant [1]. Curtailment costs could become significant at higher penetrations of wind as they were in ERCOT when 17% of wind energy was curtailed in 2009. Assuming a large expansion of the transmission grid necessary to support 20% wind, EWITS estimated that curtailments would range from 3.6% to 10% [8].

Some PPA contracts compensate wind generators for curtailed wind via make-whole payments to wind generators, although rules vary by region [31]. We did not include curtailment payments here as an ECB, as reduced capacity factors due to weak wind resources, curtailment, or any other reason should not be included in the PPA. Sustained compensation for curtailment would not incentivize wind developers to develop in areas that are most cost effective per unit of electricity actually delivered to the grid. This is the precedent set for fossil fuel plants whose compensation is based on delivered electricity or delivered capacity.

**Local environmental damages**

Wind energy development has environmental costs that include fragmentation of local ecosystems, bird and bat collisions, noise pollution, and visual pollution. Developers may indirectly internalize mitigation costs for some of these damages through PPAs. For example, local landowners are compensated through lease payments for tolerating visual and noise pollution on their property. Ecological damages may be quantified through mitigation costs for habitat destruction. In California, developers pay to set aside some amount of land per acre disturbed based on the ecological sensitivity of the land affected. However, "no obvious compensation ratio will offset bird and bat collisions with wind turbines" [32]. Therefore, California advises developers to "consult with the California Department of Fish and Game (CDFG), U.S. Fish and Wildlife Service (USFWS), and species experts in the development of site-specific ratios and fees to use in establishing compensation formulae" [32].

Social costs such as visual and noise pollution and wildlife effects are real costs of wind power. However, because these damages are site specific, may be internalized in PPAs, and have "no obvious compensation" method, we omitted these damages in our quantifications for ECBs.

**Pollution reduction benefits**

A primary benefit of wind energy is pollution reduction. Because wind has very low short-run marginal costs, it is dispatched before more expensive generators. If wind displaces fossil-fueled generators, it reduces net grid emissions. We assume that the addition of wind will result in a net reduction in GHG and criteria pollutants, providing external benefits that can be valued by the social damages that would have been caused by these avoided pollutants. This may not be true if emissions are subject to a binding cap; this is not currently the case in PJM, and is unlikely to be in coming years (see Results & Discussion section below).

Emission reductions are typically given as pounds of emissions avoided per MWh of electricity produced by wind. We monetized the benefit of pollution reductions with the estimated external cost of each pollutant. We modeled pollution reduction benefits in the low wind and high wind scenarios as triangular distributions. We used PHORUM to simulate how adding wind to PJM in 2012 would have changed each plant's annual power generation and emissions. We find that wind offsets predominantly coal generation. In the low wind scenario, 77% of the generation offset was coal; in the high wind scenario, coal was 91% of the generation offset. If gas prices were to fall significantly such that combined cycle plants operated as baseload in place of coal, we would expect pollution reduction benefits to decrease.

$CO_2$ emission reductions are valued with a social cost of carbon (SCC) of \$12 - \$114/ton, with a mode of \$39/ton (2010 dollars), the US government's estimates of SCC for 2015. The low and mode cases are average damage estimates for 5% and 3% discount rates, respectively. The high damage case is the $95^{th}$ percentile of damages under a 3% discount rate [33]. These are the bounds for our distribution of GHG reduction benefits (Table 3-3).

We valued criteria pollutant reductions ($NO_x$, $SO_2$, 2.5 micrometer particulate matter ($PM_{2.5}$)) with the AP2 model, a reduced form, integrated assessment model that links emissions of criteria pollutants to human health and environmental damages for all U.S. counties [34]. AP2 uses Monte Carlo analysis to provide uncertainty estimates for all damages, accounting for variations in value of statistical life, dose-response functions, and the air transport model. We estimated the uncertainty of damages caused by emissions from PJM plants using AP2's raw Monte Carlo results, which were provided by the model's developer. For each of AP2's Monte Carlo cases, we found the location-specific damage rate for each plant, which we summed to find

total damages caused by PJM plants.  We identified the 5th, 50th, and 95th percentiles of the resulting distribution as the bounds for our distribution of wind's criteria pollutant benefits.

In the high wind scenario, it might be argued that AP2's baseline emissions are affected enough so that the human health effects are no longer accurate. In the case of $SO_2$, there is clear evidence that $PM_{2.5}$ formation is linear [35].  Large cohort studies have found $PM_{2.5}$ concentration-response functions and mortality are also linear with no threshold across the range of observed concentrations [36] [37].  Thus, for our high wind case at 20% wind, the AP2 model predictions are justified.

Since 2010, the year for which our base data are available, emissions of $CO_2$ and criteria pollutants have dropped significantly in PJM due to lower natural gas prices, the Clean Air Interstate Rule (CAIR) [38], and the Mercury and Air Toxics Standard (MATS) [39].  2012 emissions of $SO_2$ were 42% lower than 2010 levels in PJM states, and $NO_X$ and $CO_2$ emissions have both dropped 15% [40].  To compensate for these reductions, we reduced the simulated 2010 emissions and associated damages from each plant by 42% for $SO_2$, 15% for $NO_X$, and 15% for $CO_2$.  This adjustment ignores any changes to the dispatch order that may have occurred since 2010.  We have applied this adjustment in the results that follow.

## 3.3  RESULTS & DISCUSSION

Table 3-3 summarizes the parameters used in our Monte Carlo analysis of external costs and benefits in PJM. External costs are significant when compared to private costs – the average PPA price in 2012 was ~$50/MWh in the PJM region [1]. However, external costs are much smaller than both GHG emission reduction benefits and criteria pollutant emission reduction benefits (Figure 3-3). Emission reduction benefits are higher in PJM than other ISOs due to the

combination of PJM's reliance on high emitting fossil-fueled generators and high population, resulting in increased pollution exposure compared to other ISOs.

Table 3-3 External cost and benefit parameters used in Monte Carlo simulation.

| Cost and benefit categories | Low wind scenario ($/MWh) | | | High wind scenario ($/MWh) | | |
|---|---|---|---|---|---|---|
| | Lower bound | Mode | Upper bound | Lower bound | Mode | Upper bound |
| Operational costs | $0 | $2 | $4 | $2 | $4 | $10 |
| Grid reinforcement and expansion | $0 | $16 | $48 | $4 | $15 | $35 |
| Greenhouse gas reductions | $9 | $30 | $87 | $9 | $31 | $87 |
| Criteria pollutant reductions | $15 | $57 | $164 | $19 | $70 | $198 |

Monte Carlo simulation results are shown in Figure 3-3. Total external costs have an expected value of $23/MWh in both the low wind and high wind scenarios. The monetized external benefits from pollution reduction exceed the monetized external costs in both the low and high wind scenarios. For the low wind scenario, expected pollution reduction benefits exceed expected external costs by $97/MWh, with a 90% confidence range of $40/MWh - $160/MWh. In the high wind scenario, expected pollution reduction benefits exceed expected external costs by $114/MWh, with a 90% confidence range of $50/MWh - $190/MWh. The probability that monetized external costs exceed pollution reduction benefits is less than 1% for both scenarios.
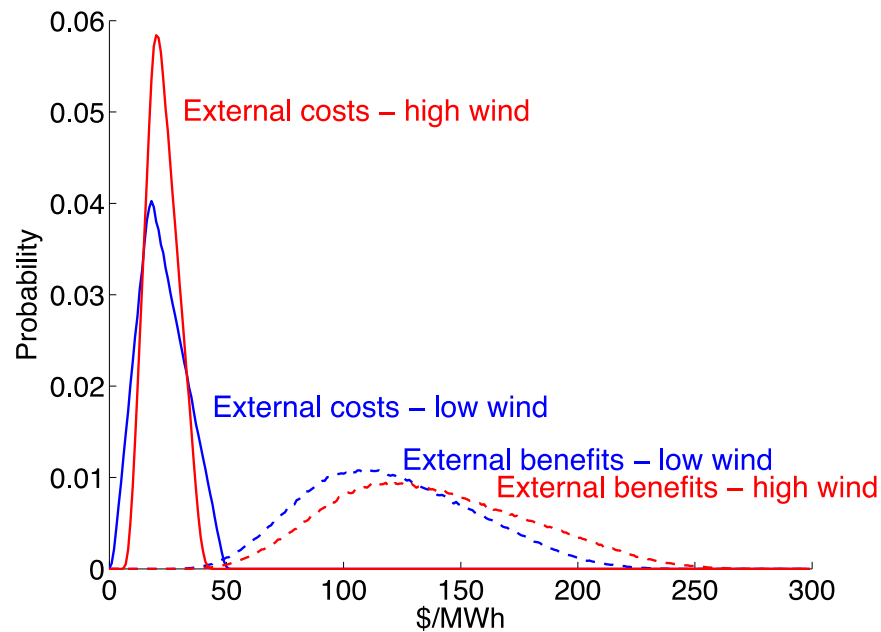
Figure 3-3. Distribution of total external costs and benefits. External costs and benefits are larger in the high wind scenario than the low wind scenario. Total external benefits are highly uncertain but have a very high probability of being significantly greater than costs.

The analysis presented here is of average ECBs under the high and low wind penetration scenarios, not ECBs at the margin. Other research has shown that marginal integration costs increase with increasing wind penetrations [1]. Therefore, the marginal external costs are likely higher than the average external costs we quantify here. It is less clear if emission reduction benefits increase or decrease on the margin. This will depend on if higher penetrations of wind increasingly offset high-emitting generation or low-emitting generation. Factors such as fuel price, the makeup of the generation fleet, and timing of wind generation will determine the marginal benefit of wind.

**External benefits under a future, cleaner grid**

Over the next decade, several rules by the U.S. Environmental Protection Agency (EPA) are expected to force many of PJM's coal generators to either retire or retrofit with improved

emission control technologies. Rules include the Clean Air Interstate Rule (CAIR), which capped emissions of $NO_x$ and $SO_2$ [38]; the Acid Rain Program, which capped emissions of $SO_2$ and has since been superseded by CAIR [41]; the Mercury and Air Toxics Standard (MATS), which limits emissions of mercury and primary particulate matter [39]; and the forthcoming rules placing $CO_2$ restrictions on existing power plants [42]. The EPA has proposed the Cross-State Air Pollution Rule (CSPAR) to replace CAIR [43]. The U.S. Supreme Court recently upheld CSPAR, which will likely replace CAIR [44]. PJM anticipates as much as 20 GW of coal capacity is at risk of retirement by CAIR/CSAPR and MATS, or 25% of total coal capacity. An additional 29 GW of capacity may need at least two retrofits to comply with the rules [45].

Two future scenarios are possible under the EPA regulations. The first scenario is that the emission caps established by CAIR/CSPAR bind. In this case, total emissions of $NO_x$ and $SO_2$ will be fixed at the emissions cap and new additions of wind will not result in a net reduction in emissions. Rather, wind will affect the price that other generators must pay for $NO_X$ and $SO_2$ emission permits. The EPA anticipates permit prices will be \$1,300/ton for $SO_2$ and \$2,100/ton for $NO_X$ in 2015 (2010 dollars) [38]. The anticipated $SO_2$ permit price is much lower than the health damages caused by $SO_2$ emissions from PJM plants. The AP2 model estimates the median damage per ton of $SO_2$ across all PJM coal plants has a 90% confidence range of \$9,000 - \$17,000 per ton, depending on location. If CAIR/CSPAR emission caps bind, significant amounts of wind would put downward pressure on permit prices. The external emission benefit of wind in this scenario would be the reduction in permit prices paid by other generators, due to the addition of wind to the system. This second order effect may be small relative to the EPA's anticipated permit prices.

In states subject to binding CAIR/CSPAR emission caps, additional wind does not reduce criteria pollutants. To simulate this effect, we repeat the analysis above but assume wind provides no external criteria pollutant emission benefits. In this context, wind's net external benefit is reduced to an expected value of $19/MWh for both the high wind and low wind scenarios. Expected net benefits are positive because greenhouse gas reduction benefits exceed external costs. The probability of net benefits being negative is 18% in the low wind scenario and 16% in the high wind scenario. We therefore conclude that state renewable portfolio standards are still warranted in PJM states under binding emission caps, although their benefits will be significantly reduced.
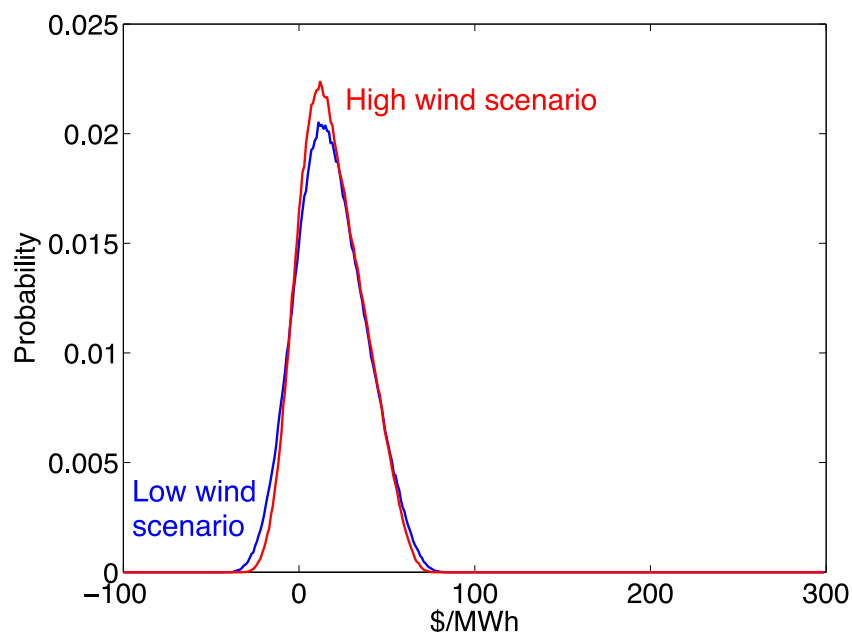


Figure 3-4: Distribution of wind's net external benefits under a scenario in which criteria pollutant emissions are subject to a binding cap, and wind provides no criteria pollutant emission reduction benefits.

The more likely scenario is that emission caps do not bind. Due to significant wind deployment, low natural gas prices, and tightened fossil plant emission regulations under MATS, caps are not expected to bind [46]. In this scenario, new additions of wind would reduce criteria

pollutant emissions and should be valued by the human health benefits they induce.   These

benefits will be lower than those in Table 3-3 if criteria pollutant emission rates from coal and oil

plants continue to drop as mandated by MATS.  How much emission benefits fall will depend on

the specifics of which plants retrofit or retire.  Because our modeling shows ~85% of total health

damages are due to $SO_2$, any reductions in the $SO_2$ emission rates of PJM plants will greatly

reduce the criteria pollutant benefits of wind.  Halving current PJM $SO_2$ emission rates would

result in expected pollution reduction benefits exceeding expected external costs by $64/MWh

and $74/MWh for the low and high wind scenarios, respectively.

We also note that there is considerable uncertainty in health damages across different

models.  Levy et al. [47] find that median damages per ton across all U.S. coal plants in 1999 had

a 90% confidence range of $6,000 to $50,000 per ton for $SO_2$; according to AP2 the median

damages per ton of $SO_2$ are $9,000 - $17,000 per ton.

Two PJM member states, Maryland and Delaware, are subject to the Regional

Greenhouse Gas Initiative (RGGI), a regional cap-and-trade program for $CO_2$.  However, $CO_2$

emissions from plants in Maryland and Delaware are less than 10% of total PJM $CO_2$ emissions.

Furthermore, the market clearing price for $CO_2$ permits has been much lower than the social cost

of carbon estimates of the US government [48] [33].  Therefore, RGGI is unlikely to have a

significant effect on PJM $CO_2$ emissions.

**Market implications**

The addition of wind to electric power systems creates external costs and benefits that are

not priced in today's markets. These external costs and benefits (ECBs) are highly uncertain and

vary between markets. We find that the external costs of wind are primarily due to grid

reinforcement and expansion costs and resource adequacy costs.  In PJM, our estimate of the

expected value of total external costs is $23/MWh in both the low wind scenario and a high wind

scenario with 20% of energy from wind. The external benefits wind creates by reducing GHG and criteria pollutant emissions are expected to exceed total external costs by $97/MWh for the low wind scenario and $114/MWh for the high wind.  These net external benefits are significant compared to wind's traditional levelized cost ~$80/MWh [49].  We therefore recommend that policies be established to incorporate the external costs and benefits of wind into the private decision making of wind developers.

Adding wind to PJM is anticipated to reduce criteria pollutant emissions and human health damages because existing emission caps are not expected to bind [46].  If caps do not bind but criteria pollutant emission rates from coal and oil plants continue to fall below 2012 levels, as mandated by MATS, the pollution reduction benefits of wind will be reduced. Under the scenario in which CAIR/CSPAR results in binding emission caps at anticipated permit prices, additional wind will not reduce criteria pollutant emissions and external costs may exceed external benefits.  If these caps bind at anticipated permit prices, state renewable portfolio standards will have fewer benefits than if they do not bind.

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# Chapter 4: CONSUMER COST EFFECTIVENESS OF $CO_2$ MITIGATION POLICIES IN RESTRUCTURED ELECTRICITY MARKETS

## ABSTRACT

We examine the cost of carbon dioxide mitigation to consumers in restructured USA markets under two policy instruments, a carbon price and a renewable portfolio standard (RPS). To estimate the effect of policies on market clearing prices, we constructed hourly economic dispatch models of the generators in PJM and in ERCOT. We find that the cost effectiveness of policies for consumers is strongly dependent on the price of natural gas and on the characteristics of the generators in the dispatch stack. If gas prices are low (~$4/MMBTU), a technology-agnostic, rational consumer seeking to minimize costs would prefer a carbon price over an RPS in both regions. Expensive gas (~$7/MMBTU) requires a high carbon price to induce fuel switching and this leads to wealth transfers from consumers to low carbon producers. The RPS may be more cost effective for consumers because the added energy supply lowers market clearing prices and reduces $CO_2$ emissions. We find that both policies have consequences in capacity markets and that the RPS can be more cost effective than a carbon price under certain circumstances: continued excess supply of capacity, retention of nuclear generators, and high natural gas prices.

## 4.1 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has begun a rulemaking process to regulate greenhouse gas emissions from existing power plants through Section 111(d) of the Clean Air Act [1]. This section requires states to meet federal standards through EPA approved State Implementation Plans (SIPS). SIPS may include "market-based instruments, performance standards, and other regulatory flexibilities" [1]. One of the significant state-to-state differences is the presence or absence of organized electric power markets. Here we examine the cost effectiveness of $CO_2$ mitigation policies in PJM and ERCOT.

There appears to be a consensus among economists that a price on carbon is the favored policy mechanism for its efficiency [2] [3] [4] [5] [6]. As an example, Metcalf writes, "For economists, the obvious choice is to move toward market-based environmental mechanisms that put a price on greenhouse gas emissions" [6].

However, policy-makers have unique perspectives when quantifying costs. Policymakers do not generally follow the perspective of neoclassical welfare or public economics that wealth transfers away from consumers are welfare neutral. On the other hand, such transfer payments are important to elected and appointed officials; they are sensitive to costs from the perspective of their constituents — consumers. Federal and state administrations have explicitly cited increased prices for consumers as undesirable, using language such as "...ensure that the standards are developed … with the continued provision of reliable and affordable electric power for consumers and businesses" [1]. Lisa Jackson, EPA Administrator from 2009-2013, echoed this perspective by stating that a key principle of the regulations will be to "…implement the most cost-effective measures that do not burden small businesses and nonprofit organizations" [7]. State policy-makers generally view costs from the consumer perspective. A meta-study by

Lawrence Berkeley National Laboratory (LBNL) on state renewable portfolio standards (RPS) quantified carbon abatement costs using, "… consumer costs, which often include wealth transfers to generators and do not necessarily reflect the true social cost of each state RPS policy" [8].

The assumption of neutrality towards wealth transfer payments is particularly important in restructured markets. Electricity is a commodity in restructured markets, where consumer costs are driven by wholesale payments quantified by market clearing prices. Carbon policies may either raise or lower market clearing prices and the differences have large transfer payment implications. Existing low carbon generators could receive a windfall profit from a carbon price. Carbon intense generators would lose a portion of their producer surplus to tax revenue (that we assume here is used for reduction of consumer taxes).

In order to estimate consumer cost and tax revenue effects of carbon mitigation policies in restructured markets, we examine two policies to reduce $CO_2$ emissions: a carbon price and renewable energy standards. For each policy, we observe how sensitive cost effectiveness is to the price of natural gas by varying the price from $4 to $7/MMBTU. We compare the differences in cost effectiveness if transfer payments away from consumers are considered neutral or a cost. We also examine how the change in profits in energy markets affects PJM's capacity market. In addition to estimating the costs in PJM, we examine ERCOT to see if our results are sensitive to a different mix of generators.

We find that from the social perspective, where wealth transfers are neutral, a carbon price is indeed the most cost effective mechanism. For consumers, however, an RPS may be more cost effective than a carbon price when natural gas is expensive (price to electric power generators of $7/MMBTU or more). Expensive gas requires a high carbon price to induce fuel

switching and this leads to wealth transfers from consumers to low carbon producers. The RPS

may be more cost effective for consumers because the added energy supply lowers market

clearing prices and reduces carbon emissions. We find that both policies have consequences in

capacity markets because they affect the profits of fossil generators. Renewables supply energy

but supply very little capacity [9], and the RPS is more cost effective than a price on carbon for

consumers only if existing capacity supply remains adequate in addition to high gas prices.

## 4.2 METHODS

We use as a metric for cost effectiveness the cost per unit of reduced greenhouse gas

emissions, dollars per tonne of $CO_2$ ($/t$CO_2$) [10]. We estimate cost effectiveness from two

perspectives: the "social perspective" and the "consumer perspective". We define the first

perspective as the "social perspective" because we assume that wealth transfers are neutral. Our

metric for estimating cost effectiveness from two perspectives is shown in Equations 1 and 2

below. The social perspective includes social costs (capital, O&M, fuel costs) but exclude

wealth transfer payments (profits or taxes).

$$Cost\ Effectiveness\ (Social) = \frac{\Delta Social\ Costs}{\Delta CO_2\ Emissions}(1)$$

We define the second perspective as the consumer's perspective. From the perspective of

consumers in restructured markets, costs are quantified by differences in wholesale payments net

of any related change in tax revenue. Tax revenue is increased by a carbon price and decreased

by renewable energy subsidies. It has been shown that the changes in tax revenue would not

equitably affect consumers even if the tax revenue was redistributed to households because lower

income households spend a larger share of their income on energy [6]. Here, we do not consider

the issue of equitable tax distribution and assume the changes in tax revenue affect consumers

equally. In this approximation, cost effectiveness of carbon mitigation policies can be estimated for consumers as:

$$Cost\ Effectiveness\ (Consumer) = \frac{\Delta Wholsale\ payments + \Delta Tax\ Revenue}{\Delta CO_2\ Emissions}(2)$$

To examine the difference of wholesale payments in energy markets under a carbon price and under an RPS, we created an hourly economic dispatch model of the generators in PJM and ERCOT. The dispatch model calculates marginal costs for all generators then dispatches the least expensive generators necessary to meet load on an hourly basis. All variable costs, including a price on carbon, were assumed to be passed on as marginal costs in the bids of generators. The market clearing price is set by the marginal generator, and all generators receive the market clearing price for that hour. The model might be thought of as using a load duration curve approach, because it does not take into account unit commitment.

Hourly load and hourly wind generation for 2012 were obtained from ERCOT and PJM databases [11] [12] [13] [14]. Power plant fuel costs, heat rates, variable O&M costs, and carbon intensities for each region were obtained from Ventyx Velocity Suite [15]. We assumed that fuel costs remained constant except for natural gas which we varied from \$4 to \$7/MMBTU. Marginal costs for nuclear and coal plants are shown in Figure 4-2 below.

The dispatch model neglects transmission, ramping, and security constraints in addition to forced outages. Under some circumstances, these simplifications could mask appreciable increases in locational marginal prices (LMP's) if the combined effect of their inclusion were to severely limit supply. Exploring the nuances of any singular or combined limitation on supply is beyond the scope of this analysis. Rather, our intention is to demonstrate how consumers could

be affected under distinct mixes of generators—PJM (diverse mix of generators with significant nuclear) and ERCOT (gas-heavy with significant coal)[1].

On the consumer side, we make the assumption that demand is inelastic to price changes because the value is relatively small and uncertain [16] [17] [18]. There is also concern over how much of the reduction would occur because of inter-state leakage [19]. Fischer et al. showed that supply elasticity values can influence the cost of policies to consumers [20]. However, Fischer et al. as well as other research [8] note that the elasticity values are uncertain and that policies would affect natural gas prices on the order of a few cents per MMBTU. Therefore, we neglect the long term supply elasticity values of fossil fuels.

Because we neglect consumer price elasticities, we emphasize that this research should not be interpreted as a net social welfare analysis. Our objective is to inform policymakers how cost estimates differ when viewed from the perspective of consumers given a wide range of plausible costs for renewables and natural gas.

**Time Frame and Power Plant Turnover Assumptions**

Policy cost estimates inherently require uncertain assumptions over some arbitrarily chosen time horizon. We make the following simplifying assumptions.

We limit the analysis to the short term by assuming demand and the mix of generators in each region stays the same as it was in 2012. We assume demand remains constant because it has been from 2005 through 2012 [21]. Both PJM and ERCOT project peak demand to increase by only 1% annually from 2014 to 2024 [22] [23].

With excess capacity and relatively flat demand, construction of new capacity is expected to be low [24]. Inexpensive shale gas further disincentivizes new power plants because of lower

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[1] We also modeled MISO. We discuss below why we included the results in the supporting data rather than in the main text.

market clearing prices in energy markets. New power plants are not profitable at low carbon prices according to our dispatch model. Therefore, we model a mix of generators identical to that in 2012.

It is likely that older, less efficient power plants may retire in both PJM and ERCOT. In ERCOT, 10 GW of natural gas steam generators have already retired since 2005 [25]. In PJM, as much as 20 GW of coal plants are thought to be at risk of retirement due to pending environmental regulations [26]. In the supporting data (SD), we examine an alternate scenario in which 18 GW [26] of small, old coal plants are retired in PJM. We find that the high heat rates of these generators preclude them from greatly affecting energy markets; thus their exclusion does not substantially alter our findings.

Though the retirement of older power plants may not affect our estimates in energy markets, retirements may affect the capacity market. When new capacity is needed (due to retirements or demand increases), the decision will be based on the conditions of energy markets and capacity markets along with environmentally related incentives. After presenting our results for policies in energy markets, we examine how carbon policies may affect capacity market bids if either existing coal or new NGCC power plants are on the margins.

**Carbon Dioxide Mitigation Quantity**

A price on $CO_2$ disadvantages coal fueled generators and causes other generators to be dispatched first; this is termed fuel switching. Our model estimates for each RTO the amount of carbon reduced due to a given carbon price (Figure 4-1) over a baseline set by the $CO_2$ emissions output of our dispatch model at a given natural gas price and 2012 modeling data. Figure 4-1 shows that the effectiveness of the carbon price is dependent on the price of natural gas and the

amount of gas capacity in each region. For each region, the line stops when market conditions induce either new NGCC plants or new wind plants.
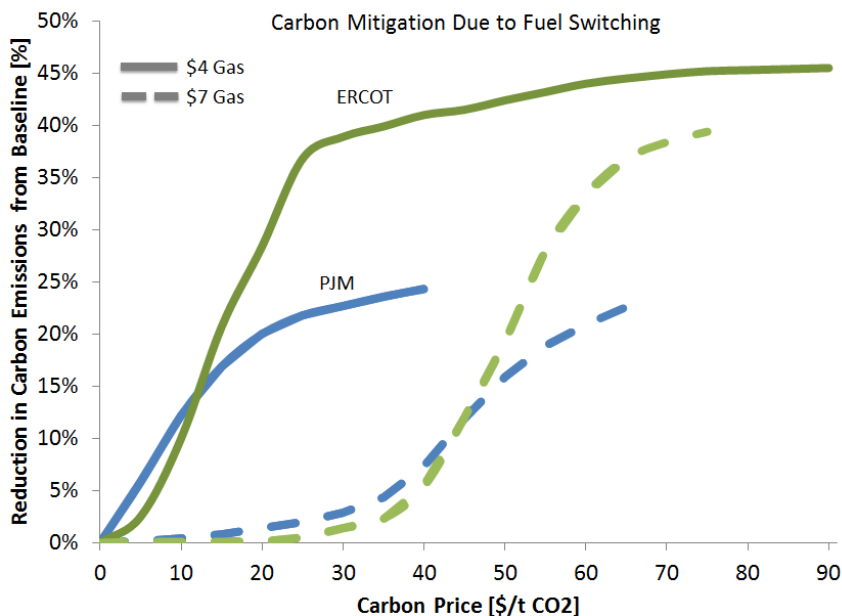


Figure 4-1*: Carbon mitigation due to fuel switching as a result of a carbon price. Solid lines are for natural gas at $4/MMBTU; dashed lines are for $7 gas. The lines stop when new capacity is profitable as a result of a carbon price and natural gas price. In the $4 gas case, new NGCC plants are induced. In the $7 gas case, new wind plants are induced. We assume that the levelized cost of wind is $85/MWh and the levelized cost of a new NGCC plant is $135/MW-year [27]. NGCC plants may be profitable at slightly lower carbon prices than indicated in the figure because of revenue from capacity markets.*

Of the three regions examined, MISO has the least fuel diversity and the dominance of coal means that market clearing prices rise quickly with carbon prices. We performed the analysis for MISO but found that this research was not as applicable to this region because new plants are induced at such a low carbon price and the lack of fuel diversity limits wealth transfers. Methods and results for MISO are given in the supporting data.

**Transfer Payment Implications of a Carbon Price**

Should gas prices reach $7/MMBTU, a higher carbon price would be necessary to induce new power plants or fuel switching. These price changes lead to transfer payments (Figure 4-2). In PJM, the carbon price raises the market clearing price and leads to increased profits for low carbon generators. In ERCOT, a carbon price may cause transfers from producer surplus to tax

revenue.  ERCOT does not have as many existing low carbon generators to take advantage of the carbon price.  If coal is dispatched despite the carbon price, its producer surplus is transferred to tax revenue.  The price of electricity is (to first order) unaffected, since gas sets the market clearing price. The changes in profits affect capacity markets and may cause some generators to extend or cease operations; we discuss this further below.
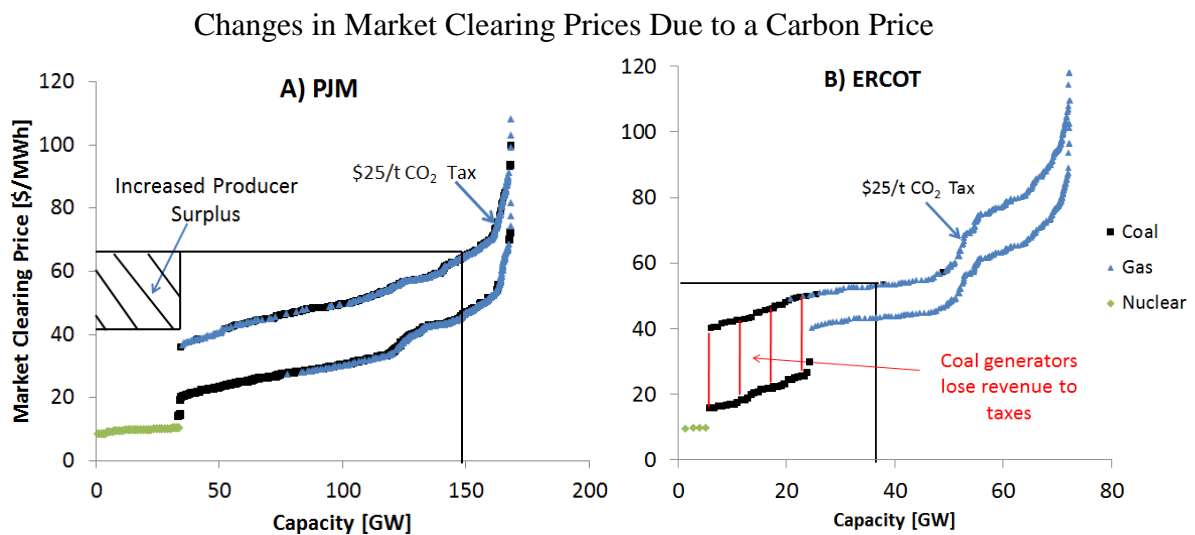
### Changes in Market Clearing Prices Due to a Carbon Price



Figure 4-2: *The effect of a $25/tonne $CO_2$ price in (a) PJM and (b) ERCOT.  In PJM, low-carbon generators benefit from a price on carbon but do not change their order in the dispatch stack.  In ERCOT, carbon intense generators that remain in the dispatch stack lose profit to tax revenue.*

**Renewable Portfolio Costs and Transfer Payment Implications**

A price on carbon raises market clearing prices; renewables lower it.  Renewable generators increase energy supply with very low short-run marginal cost, push the energy supply curve to the right, and lower market clearing prices (SD Figure S2) [8] [28].  The lowered market clearing prices decrease the profits of fossil generators [8] [28].  Here, we make the assumption that these savings are passed on to consumers in the form of lower wholesale power prices.

We assume that whatever technology is used to meet the RPS has the same hourly production pattern as wind energy did in 2012[2].  We assumed the cost of the renewable energy to

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[2] In the supporting data, we show that our conclusion is unchanged if the RPS production pattern is base-load.

consumers is equal to its levelized cost of electricity (LCOE).  Renewable energy is induced

through a combination of revenue from bilateral power purchase agreements, renewable energy

credits, and other subsidies.  The sum of the revenue received by renewable energy developers

would be approximately equal to the LCOE.

The US DOE estimates that 500 GW of wind are available at ~$85/MWh or less, not

including integration costs or subsidies [29].  We find that the most recently available

assumptions would also yield a levelized cost of about $85/MWh: a capital cost of $1940/kW

[30], a fixed charge factor of 12%, a capacity factor of 35% [30], and O&M costs of $25/kW-

year [30].

Wind also has costs due to variability and transmission not typically included in LCOE

estimates [31].  Utilities would pass these costs onto consumers, so we include them here.  The

2012 DOE Wind Technology Market Report estimates variability costs to be in the range $2.5-

$10/MWh [30].  For transmission costs unique to wind, LBNL performed a meta-study that

found the cost of transmission to be $10-$15/MWh [32].  We add these costs, which utilities

would pass onto consumers, to estimate a total levelized cost of approximately ~$100/MWh of

wind.

We examine wider bounds than the costs described above because of the wide range of

costs found in literature [31] [33] and the unpredictability of technology and subsidies.  The

federal government (sometimes) provides a production tax credit of $23/MWh [34].  In our

results, we examine cost effectiveness if the added energy cost $80, $100, or $120/MWh from

the perspective of consumers.

## *4.3*  RESULTS

**PJM Energy Market**

In Figure 4-3, we show the marginal cost effectiveness of policies in PJM's energy market. From the social perspective, where wealth transfers are neutral, our results indicate that a carbon price is (as expected) the most cost-effective option. As theory would suggest, the marginal cost of abatement is equivalent to the carbon price. If wealth transfers are neutral, the RPS would cost approximately ~$40-$80/t $CO_2$ more than a carbon price.
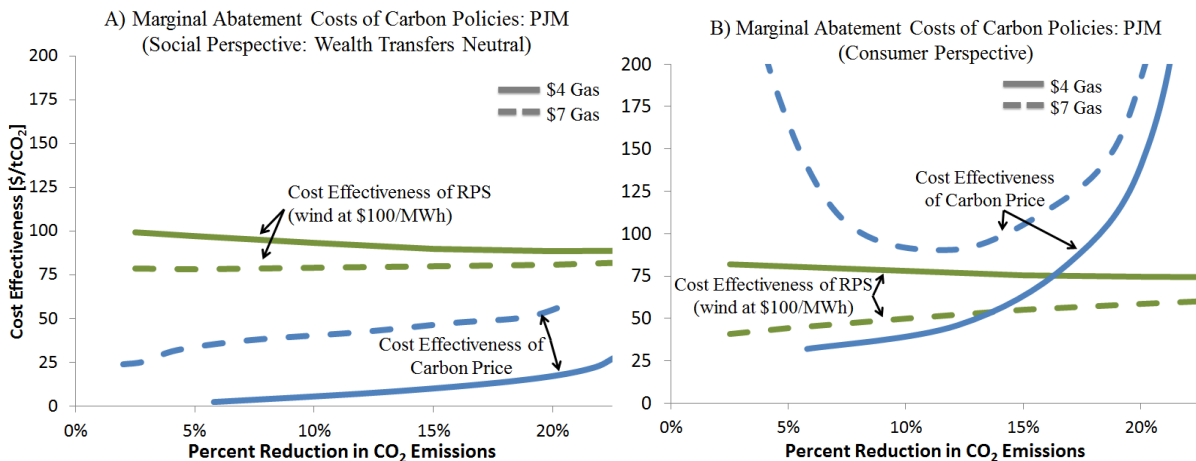


Figure 4-3: *Cost effectiveness of carbon mitigation policy options in PJM using 2012 data as the baseline. Figure 4-3(a) shows the marginal abatement costs of policies if transfer payments are neutral. The marginal cost of abatement is equal to the carbon price. Figure 4-3(b) shows the marginal abatement costs of policies from the consumer perspective. If wind costs are $80/MWh, costs are approximately $20/tCO_2 less expensive than in the figure. If wind costs are $120/MWh, costs are approximately $30/tCO_2 more expensive than in the figure. In the supporting data, we show the average cost effectiveness if a 20% reduction is required (SD Figure S4).*

From the consumer perspective, the most cost effective policy is dependent on market conditions. A carbon price is the most cost effective option for consumers at low natural gas prices and low carbon prices (less than ~$15/t $CO_2$). With high gas prices, consumers may pay less per tonne offset with an RPS. A carbon price is not cost effective with high gas prices because the high carbon price necessary (Figure 4-1) leads to a wealth transfer at the expense of consumers. The cost effectiveness of the RPS is improved by higher natural gas prices because the supply of renewable energy does more to suppress market clearing prices. In the next section we consider capacity markets.

**PJM Capacity Market Implications**

Power plant bids in capacity markets are driven by fixed costs (PJM refers to these as "avoidable costs" [35]) less profits made in energy markets [36]. Carbon dioxide mitigation policies affect capacity markets because they affect the profits of generators in energy markets. If generators increase their bids in capacity markets as a result of carbon policies, the cost to consumers can be appreciable [8].

Capacity markets are volatile [36] [37] [38]. For the PJM Base Residual Auctions from 2007 to 2017, the RTO resource clearing price has varied between $16-$174/MW-day [39]. This is a consequence of uncertain demand [38] and the steep supply curve of capacity market bids in PJM; it increases by over $300/MW-day for the last 10 GW offered [39].

Given the volatility of capacity markets, models of the market do not exhibit a high degree of accuracy. However, it is feasible to examine how policies affect the bids of plants that may be on the margin in capacity markets now and in the future—existing coal generators or new NGCC power plants. Coal plants appear to be on the margins in the PJM capacity market, as 10 GW of coal plants did not clear in the 2016/2017 capacity market auction [39].

In Figure 4-4, we show how capacity market bids of coal and NGCC power plants change as a result of carbon policies. Without revenue from energy markets, the avoidable costs of an existing coal fired power plant and a new NGCC plant are approximately $160/MW-day and $370/MW-day, respectively [27] [35]. Lower bids are submitted to capacity markets as generators earn revenue in energy markets. We estimate that revenues from energy markets[3]

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[3] Our estimates explore energy market revenues and neglect ancillary service market revenues. Revenue from ancillary services amounted to $6/MW-day in PJM [27]. Revenues in ancillary service markets may increase due to the variability created by wind (RPSs in the PJM states require 14% renewables by 2026). However, because the amount is less than 10% of the capacity clearing price, we did not include it in this analysis.

would allow the power plants to make bids of \$105/MW-day and \$350/MW-day, respectively[4].

We use The Brattle Group's estimates for the cost of new entry (CONE) in PJM for NGCC

plants [27]. Coal plant performance is based on data from the 2012 PJM State of the Market

Report [35] and marginal costs of existing power plants in our dispatch model [15]. The bids of

generators change as profits are affected by carbon policies (Figure 4-4).
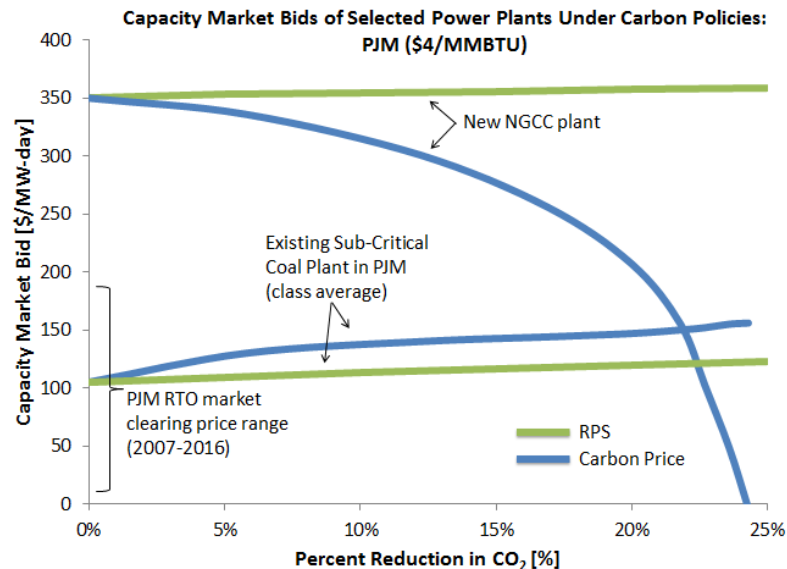


Figure 4-4: *Modeled capacity market bids in PJM of new NGCC plants and existing coal plants under a carbon price and an RPS assuming a gas price of \$4/MMBTU.*

A $CO_2$ price has a larger effect on capacity bids than does an RPS because gas and coal

plants switch their positions in the dispatch stack. The RPS does not change the order of the

dispatch stack; it simply displaces the marginal generator. For a 20% reduction in $CO_2$, the RPS

raises the bid of an existing coal power plant by \$15/MW-day whereas a carbon price raises it by

\$40/MW-day.

As long as existing generators satisfy capacity supply, the capacity market reaction from

policies appears moderate and unlikely to change the decision of a policy-maker. Over a year, a

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[4] These estimates assume that a coal plant has a marginal cost of \$25/MWh per data from Ventyx Velocity Suite [15]. We assume that the NGCC plant has a marginal cost of \$29/MWh per NGCC performance data from Brattle's CONE analysis [27] and a gas price of \$4/MMBTU. The coal plant earns higher profits in energy markets and can make lower capacity market bids as a result.

$15/MW-day or $40/MW-day increase in PJM capacity prices would result in additional costs to consumers of $0.9B to $2.4B, respectively (with 165 GW of capacity in PJM [39]). We summarize as follows for a 20% reduction in $CO_2$ emissions. For the carbon price, the cost of mitigation increases from ~$65 to $95/tCO$_2$. For an RPS, the mitigation cost increases from ~$75 to $90/tCO$_2$.

Existing generators are unlikely to satisfy capacity supply forever, and renewables may force generators into premature retirement by reducing their profits. Let's suppose that renewables shortened capacity supply and increased capacity prices by $100/MW-day. If we add this cost to the 20% reduction RPS case, the mitigation cost increases from ~$75 to $150/tCO$_2$.

Another possible outcome of an RPS is that capacity prices remain low but renewables cause nuclear retirements. Three of Exelon's nuclear power plants did not clear in the most recent PJM capacity auction and are no longer considered "in the money" [40]. Suppose that renewables pushed these generators (4.8 GW) to retirement and emissions reduced only 12% instead of 20% because of the retirements. The cost of mitigation would then increase from ~$75 to $140/tCO$_2$.

Policy-makers may favor a carbon price simply to increase capacity supply and decrease dependence on volatile capacity markets. A carbon price makes new gas plants and existing nuclear plants more competitive by increasing profits in energy markets. An RPS would increase dependence on capacity markets by undercutting fossil profits in energy markets [8]. In order for the RPS to be cost effective for consumers, markets must retain nuclear generators, attract new capacity, and do so without causing drastic increases to capacity market prices.

**ERCOT**

As shown in Figure 4-2 above, the wealth transfer implications of a carbon price in

ERCOT are different from PJM. ERCOT has few nuclear generators, large gas capacity,

inexpensive coal, and no capacity market. The dominant wealth transfer effect of a carbon price

is coal generators losing profits to tax revenue. Figure 4-5 below shows the two perspectives of
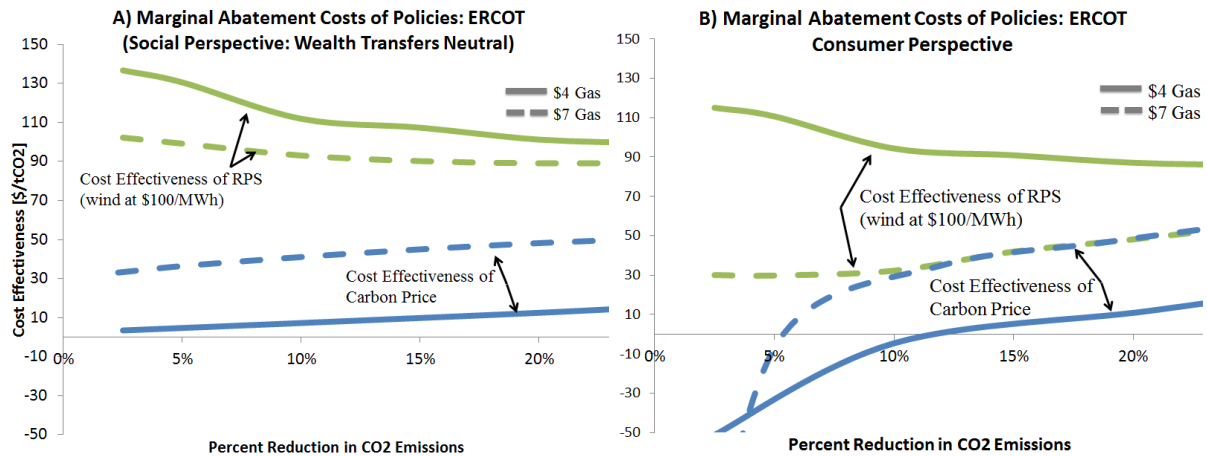
carbon policies in ERCOT.



Figure 4-5: *Cost effectiveness of carbon mitigation policy options in ERCOT. Figure 4-5(a) assumes transfer payments are welfare neutral. Figure 4-5(b) assumes the consumer perspective. From the consumer perspective, so much producer surplus is transferred to tax revenue by the carbon price that consumers surplus may increase. This causes the negative cost effectiveness estimates. Figures showing alternate costs of wind are in the supporting data. If wind costs are $80/MWh, costs are approximately $30/tCO_2 less expensive than in the figure. If wind costs are $120/MWh, costs are approximately $40/tCO_2 more expensive than in the figure above. In the supporting data, we show the average cost effectiveness if a 20% reduction is required (SD Figure S5).*

Figure 4-5 shows that a carbon price in ERCOT is more cost effective from the consumer

point of view than an RPS under the assumption that tax revenues from the $CO_2$ price accrue to

consumers. In the expensive gas case, the RPS can be cost effective for consumers because it

lowers the market clearing price in gas-heavy ERCOT.

ERCOT does not have a capacity market, so we cannot model whether coal generators

would cease operations as a result of lost profits. The RTO expects capacity to become

extremely tight with low gas prices and no capacity market [25]. The short capacity situation in

ERCOT is expected to lead to larger price spikes, which in theory effectively act as capacity payments, though market changes have been suggested [41].

We summarize our results for PJM and ERCOT for a 20% reduction in carbon dioxide emissions from the baseline year of 2012 in Table 4-1.

Table 4-1: Average Cost of Abatement for 20% Reduction of $CO_2$ [$/t$CO_2$]

| | | | $CO_2$ Price | | RPS | | $CO_2$ Price | RPS | $CO_2$ Price | RPS |
|---|---|---|---|---|---|---|---|---|---|---|
| $CO_2$ Reduced | Region | Perspective | | | | | With existing coal setting prices in the capacity market | | With new NGCC setting prices in the capacity market | |
| | | | $4 Gas | $7 Gas | $4 Gas | $7 Gas | $4 Gas | | $4 Gas | |
| 20% | | Economist | 10 | 40 | 90 | 80 | | | | |
| 20% | PJM | Consumer | 65 | 190 | 75 | 60 | 95 | 90 | -50 | 80 |
| 20% | | Economist | 10 | 40 | 110 | 90 | | | | |
| 20% | ERCOT | Consumer | 0 | -20 | 95 | 40 | | | | |

## 4.4  DISCUSSION

We examined the cost effectiveness of a carbon price and of an RPS in restructured markets. From the social perspective, where wealth transfers are neutral, we find that a carbon price is (as expected) the most cost effective mechanism. This research adds a perspective that is relevant to policy-makers: in the short term, how will these policies affect consumers?

We find that the cost effectiveness of policies for consumers is strongly dependent on the price of natural gas and the characteristics of the generators in the dispatch stack. If gas prices are low (~$4/MMBTU), a technology-agnostic, rational consumer seeking to minimize costs would prefer a carbon price over an RPS in both PJM and ERCOT. A relatively low carbon price is required to induce fuel switching when gas is inexpensive. The low carbon price minimizes wealth transfers and the marginal cost of mitigation to consumers is $\lesssim$ $50/t $CO_2$.

If gas prices are high ($7/MMBTU), for a 20% reduction of $CO_2$ in PJM, a consumer would find that an RPS mitigates $CO_2$ for an average of $60/tCO_2$, much lower than the average carbon price mitigation cost of $190/tCO_2$ (SD Figure S5).  However, in ERCOT, the consumer would find that a carbon price is considerably less expensive than an RPS as a mitigation strategy because a portion of coal generators' producer surplus is converted to tax revenue (SD Figure S6).

As long as existing generators can supply adequate capacity, the effect of policies on capacity markets is limited and would not affect a policy maker's decision.  However, if new capacity is needed, a carbon price substantially reduces the capacity market bids of new NGCC plants.  Policy-makers concerned with the low capacity supplied by an RPS could include other low carbon technologies that may have a higher LCOE [33] but that supply more capacity, such as coal with carbon capture and sequestration or nuclear.

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# Chapter 4 Supporting Data:

# Consumer Cost Effectiveness of CO$_2$ Mitigation Policies in Restructured Electricity Markets

## Analysis of 18 GW of Coal Missing in PJM

In the analysis above, we assumed that demand and the mix of generators in each region would stay the same as it was in 2012.  Pending environmental legislation may force coal generators to retro-fit, and PJM estimates that 11 GW of coal are at "high risk" of retirement and another 14 GW are "at some risk"[26].  PJM estimates that the best physical screening for plants at risk of retirement are those over 40 years old and with capacity less than 400 MW [26].  We applied this screening tool to our mix of generators and removed 18 GW of old, small coal plants from the dispatch stack.  Below in Figure 4-S1, we show results with these coal plants removed.
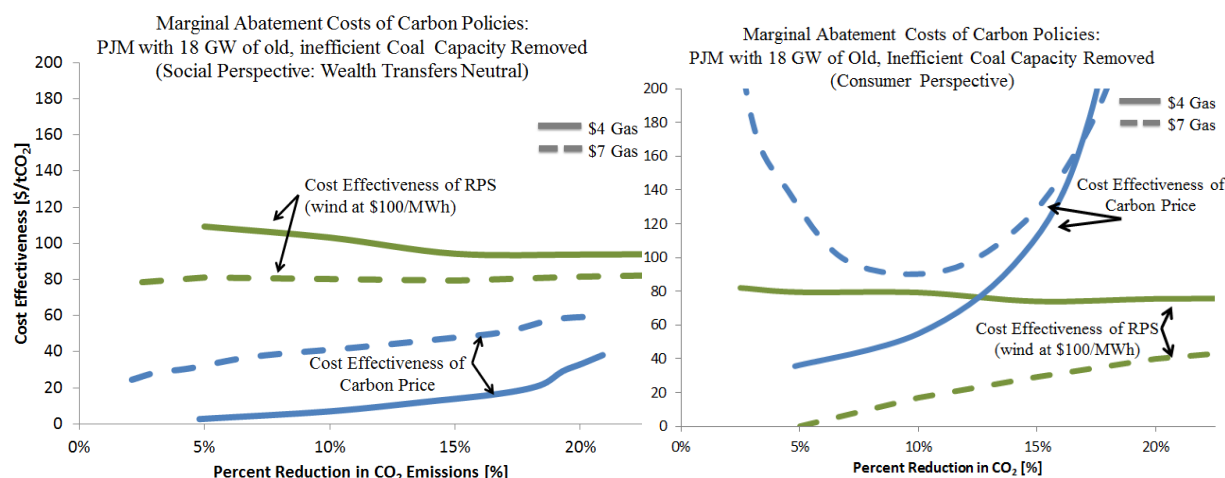


***Figure 4-S1:*** *Cost effectiveness of carbon mitigation policy options in PJM using 2012 data with 18GW of coal removed as the baseline.  The graph on the left shows the marginal abatement costs of policies if transfer payments are neutral.  The marginal cost of abatement is equal to the carbon price.  The figure on the right shows the marginal abatement costs of policies from the consumer perspective.*

Figure 4-S1 above shows similar results to Figure 4-3 of the main text.  This shows that the coal generators expected to be lost have high heat rates and are not be major contributors to our results in energy markets.

## Effect of Wind on Market Clearing Prices in PJM

In Figure 4-2 in the main text above, we show how a carbon price increases market clearing prices.  Below in Figure 4-S2, we show how renewables lower market clearing prices.
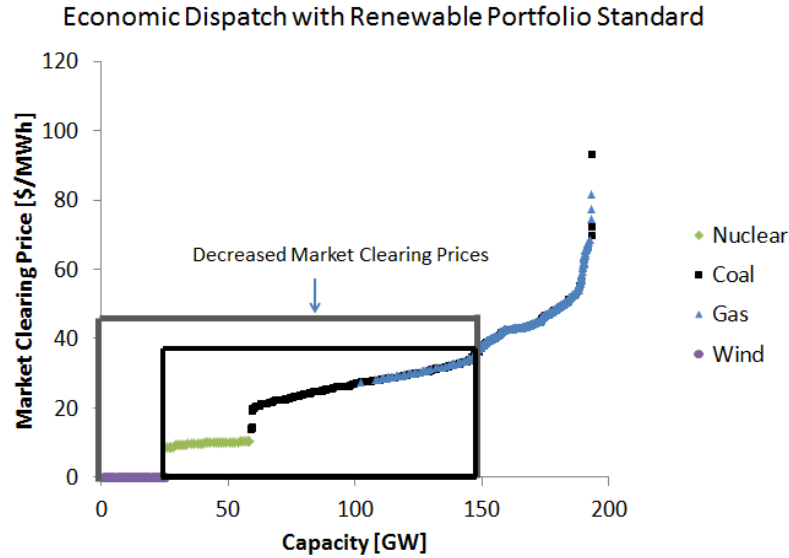
**Figure 4-S2:** *25 GW of wind are generated during a particular hour. Moving the dispatch stack to the right lowers the market clearing price from approximately $45/MWh to $38/MWh.*

## Average Cost Effectiveness in MISO

We performed the same cost effectiveness analysis for MISO as we did for PJM and ERCOT. Hourly load data was unavailable for MISO, so the MISO hourly load was estimated by scaling down PJM data based on 2012 peak load differences [42] [43]. Hourly wind production was scaled from National Renewable Energy Lab's eastern wind dataset [44] to meet annual generation levels reported for each region for 2012 [45] [46].

We found that the results were not as applicable for this research because the lack of fuel diversity leads to smaller wealth transfer effects than in the other regions (Figure 4-S3). Of the three regions examined, MISO has the least fuel diversity and the dominance of coal means that market clearing prices rise quickly with carbon prices. MISO is the only region for which the model shows that new capacity is profitable with a carbon price without reaching a 20% reduction in carbon emissions. Below in Figure 4-S3, we show Figure 4-1 from the main text with MISO included.
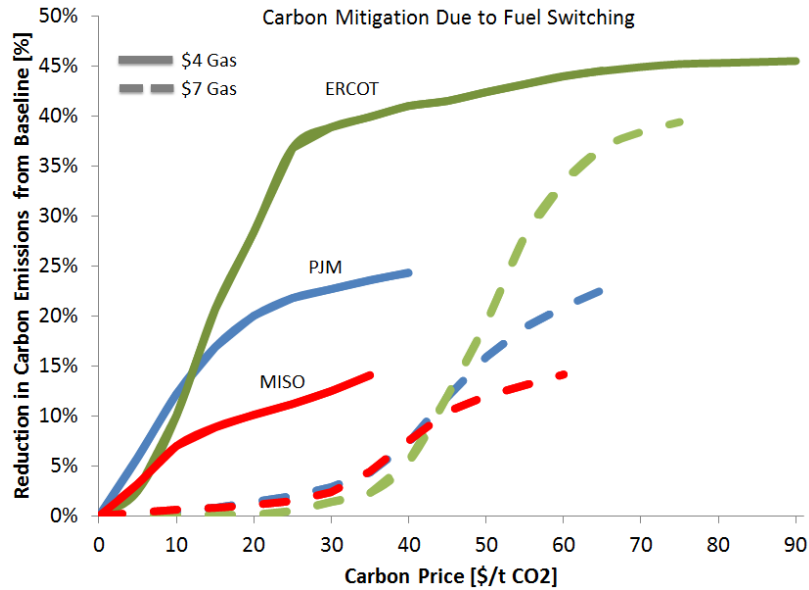
***Figure 4-S3****: Carbon mitigation due to fuel switching as a result of a carbon price.  Solid lines are for natural gas at $4/MMBTU; dashed lines are for $7 gas. The lines stop when new capacity is profitable as a result of a carbon price and natural gas price.  In the $4 gas case, new NGCC plants are induced.  In the $7gas case, new wind plants are induced.  We assume that the levelized cost of wind is $85/MWh and the levelized cost of a new NGCC plant is $135/MW-year [27].  NGCC plants may be profitable at slightly lower carbon prices than indicated in the figure because of revenue from capacity markets.*

Below in Figure 4-S4, we show the cost effectiveness of a 10% reduction in carbon emissions in MISO.  Figure 4-S4 shows that consumers would pay approximately ~$50/tCO$_2$ if either a carbon price or an RPS was used in the $7/MMBTU gas scenario.  If gas was $4/MMBTU, a carbon price would be the more cost effective option for consumers.

**Figure 4-S4:** *Cost effectiveness of mitigating carbon 10% in MISO. We varied the cost of wind between $80-$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray boxes indicate an economist's point of view where wealth transfers are neutral.*

Like other regions, an RPS is more cost effective for consumers when gas is expensive. However, because of the small differences in cost effectiveness, policy decisions are more likely to be driven by other factors.

**Average Cost Effectiveness in PJM**

Below in Figure 4-S5, we show the average cost effectiveness of a 20% reduction in
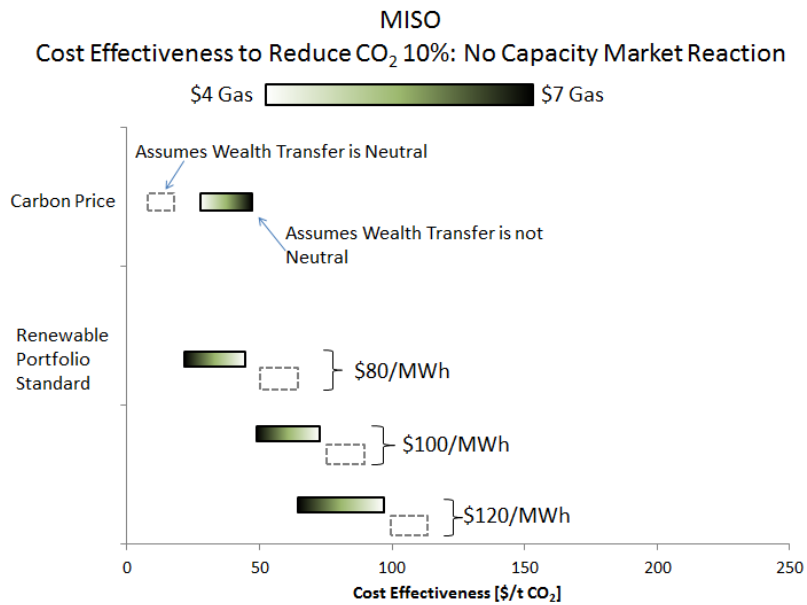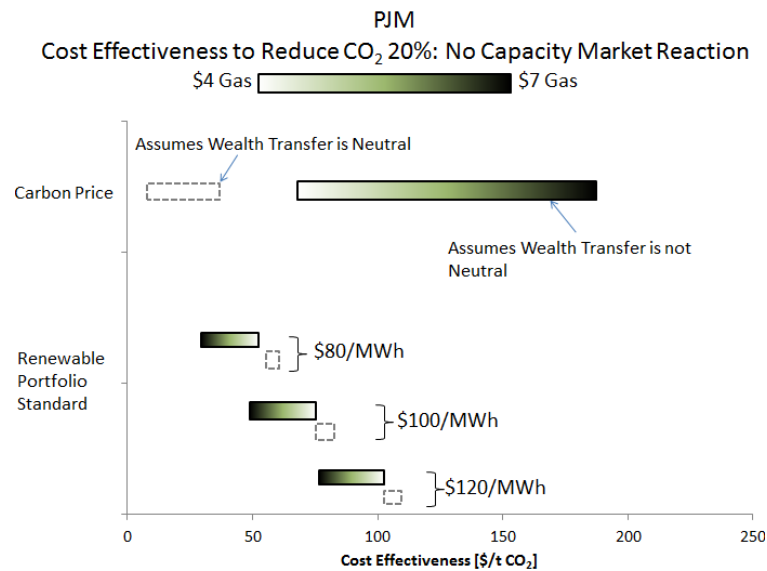
carbon emissions in PJM.



***Figure 4-S5:*** *Cost effectiveness of mitigating carbon 20% in PJM. We varied the cost of wind between $80-$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray boxes indicate an economist's point of view where wealth transfers are neutral.*

## Average Cost Effectiveness in ERCOT

Below in Figure 4-S6, we show the average cost effectiveness of a 20% reduction in
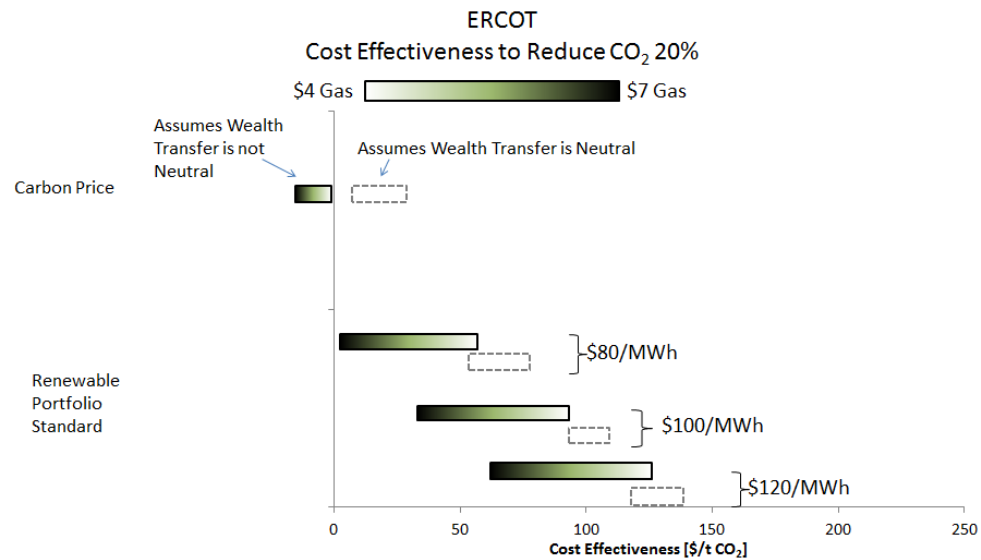carbon emissions in ERCOT.



***Figure 4-S6:*** *Cost effectiveness of mitigating carbon 20% in ERCOT. We varied the cost of wind between $80-
$120/MWh and the cost of gas from $4-$7/MMBTU. Colored boxed indicate the consumer point of view and gray
boxes indicate an economist's point of view where wealth transfers are neutral.*

**Average Cost Effectiveness for 10% Reduction in CO$_2$ Emissions**

We summarize our results for PJM, ERCOT, and MISO for a 10% reduction in carbon

dioxide emissions from the baseline year of 2012 in Table 4-S1.

Table 4-S1: Cumulative Cost of Carbon Abatement for 20% Reduction of CO$_2$ in PJM and ERCOT [$/tCO$_2$]

| CO$_2$ Reduced | Region | Perspective | Carbon Price | | RPS | | Carbon Price | RPS | Carbon Price | RPS |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | With existing coal setting prices in the capacity market | | With new NGCC setting prices in the capacity market | |
| | | | $4 Gas | $7 Gas | $4 Gas | $7 Gas | $4 Gas | | $4 Gas | |
| 10% | | Social | 5 | 30 | 90 | 80 | | | | |
| 10% | PJM | Consumer | 40 | 220 | 80 | 50 | 65 | 85 | -20 | 90 |
| 10% | | Social | 5 | 40 | 120 | 100 | | | | |
| 10% | ERCOT | Consumer | -20 | -60 | 100 | 30 | | | | |
| 10% | | Social | 10 | 30 | 90 | 75 | | | | |
| 10% | MISO | Consumer | 30 | 50 | 70 | 50 | | | | |

## Results if Renewable Output is Baseload

In the analysis above, we assumed that wind fills the entire renewable energy portfolio. For completeness, we ran the analysis for PJM assuming that the output of the renewable portfolio was baseload. The results are shown in Figure 4-S7 below.



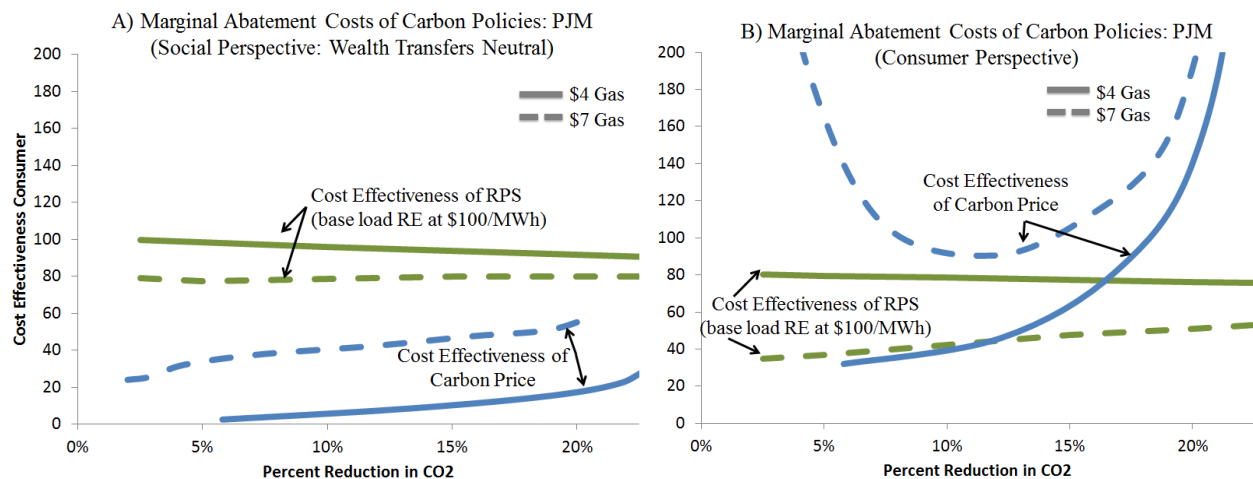***Figure 4-S7:*** *Cost effectiveness of carbon mitigation policy options in PJM using 2012 data assuming the renewable energy output is constant. The graph on the left shows the marginal abatement costs of policies if transfer payments are neutral. The marginal cost of abatement is equal to the carbon price. The figure on the right shows the marginal abatement costs of policies from the consumer perspective.*

# Chapter 5: COULD LOW CARBON CAPACITY STANDARDS BE MORE COST EFFECTIVE AT ABATING $CO_2$ THAN RENEWABLE PORTFOLIO STANDARDS?

This chapter was co-authored with Kyle Borgert and Jay Apt and has been submitted to the International Conference on Greenhouse Gas Technology (GHGT-12).

## ABSTRACT

We examine the implications of lowering electricity sector $CO_2$ emissions in PJM through a Low Carbon Capacity Standard (LCCS) instead of a renewables portfolio standard (RPS).  An LCCS would create a requirement for load-serving entities to procure new low carbon capacity (GW).  The LCCS would provide a greater balance of energy and capacity supply than a renewable portfolio standard, which requires only the supply of energy (and excludes non-renewable low carbon generators).   Approximately 25 GW of PJM generation capacity is scheduled to retire by 2019 and the RPSs currently in place in PJM will supply only 5 GW of Equivalent Load Carrying Capability (ELLC).  An LCCS, providing the same amount of low carbon energy, would supply 13 to 16 GW of ELCC.  We estimate the required reduction of capacity prices required to cover the investment cost premium low carbon capacity would require from consumers.  For example, if the energy from an LCCS costs on average $20/MWh more than energy from an RPS, the annual premium would be approximately $2.2 B.  In order for consumers to be better off with an LCCS in this example, capacity prices would have to decrease by $40/MW-day.  We find that if an LCCS were adopted, coal fired power plants with carbon capture, utilization, and sequestration (CCUS) would likely have the lowest cost per MW of capacity of all low carbon technologies, based on net Cost of New Entry (CONE) estimates.

## 5.1   INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has begun a rulemaking process to regulate greenhouse gas emissions from existing power plants through Section 111(d) of the Clean Air Act [1].  The proposed rule would establish EPA approved State Implementation Plans (SIPS) as the default mechanism for achieving federally mandated emission reductions in the electricity sector.  For many states, a renewable portfolio standard could be used as the primary policy mechanism to achieve a substantial portion of reductions in the SIP.  Here, we examine the implications of lowering $CO_2$ emissions from the electricity sector in the PJM regional transmission organization area with a Low Carbon Capacity Standard (LCCS) instead of an RPS.

Twenty nine of the United States have an RPS; 11 out of 13 PJM member states have one[5] [2].  In a restructured utility market such as PJM, an RPS serves as a requirement levied on the load-serving entities (LSEs) to annually procure a specified quantity of energy (GWh) derived from sources defined as renewable.  We propose, and here evaluate in PJM, a requirement on load-serving entities to procure new low carbon capacity (GW).  The LCCS would seek to provide greater balance of energy and capacity supply than an RPS, which requires only the supply of energy.

In most areas where wholesale markets exist in the United States, market clearing prices in energy markets are currently low due to low natural gas prices and demand which is below pre-recession levels.  Stakeholders maintain that these low prices do not provide enough revenue to stimulate new capacity [3].  The addition of renewables tends to reduce wholesale energy prices [4], further discouraging new capacity investments.  By capacity, we mean the capacity available at times of peak load, as computed by the metric equivalent load carrying capability

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[5] Of these 11, Ohio recently put a "freeze" on its RPS [40].

(ELCC) [5]. Renewables are inherently variable, and the capacity they supply is generally a significantly smaller fraction of their nameplate capacity than for thermal plants. In PJM, the ELCC of wind is 13% [6] [7]; out of 100 MW of nameplate capacity, wind would qualify for only 13 MW of capacity. Electricity markets require a balanced supply of both services, energy and capacity, to meet demand with an acceptable loss of load probability (LOLP) [8].

In 2007, PJM introduced a capacity market known as the "Reliability Pricing Model" to drive investment in new capacity [9]. To date, prices have been moderate (average ~$85/MW-day) and sufficient capacity has been supplied to the region. In 2013, the average total, "all-in" wholesale cost of energy in PJM was $54/MWh [10]. The energy portion of this cost was $39/MWh (73%) and the capacity portion was $7/MWh (13%) [10].

Although the capacity market has been successful in meeting many of its stated objectives [9], it has been volatile; ranging from a price of $16/MW-day to a price of $174/MW-day [11]. The supply curve in the capacity market is quite steep, increasing by as much as $300/MW-day over the last 10 GW offered [9]. Therefore, even a modest change in supply may cause large changes in capacity prices. For example, in the most recent PJM annual capacity auction, capacity prices doubled from $60/MW-day to $120/MW-day even as demand for supply decreased by 2 GW [11]. The price increase was "driven by supply-side effects" as imports and demand side management decreased 4.5 GW [11].

Prices in PJM's capacity market could rise significantly if more power plants retire or demand increases. New environmental regulations [12], post-Fukushima nuclear safety regulations [13], and low energy prices are accelerating coal and nuclear retirements [14] [15]. PJM estimates that 25 GW of coal capacity will retire between 2011 and 2019 with an additional

15 GW of capacity at risk of retirement [14].  Exelon has already suggested that they will be forced to close nuclear generators if energy and capacity prices remain low [16].

We examine the implications of lowering electricity sector $CO_2$ emissions in PJM through an LCCS. We quantify the energy and capacity produced by RPS requirements enacted by states within PJM and contrast against the energy and capacity produced by an LCCS.  We gauge the required suppression of capacity prices necessary to cover the investment cost premium low carbon capacity would require from consumers.  We also examine the competitiveness (on a per MW basis) of capacity offered for solar, wind, nuclear, natural gas, and coal with carbon capture, utilization, and sequestration (CCUS).

We find that if CCUS was on average $20/MWh more expensive than wind on a levelized cost of electricity (LCOE) basis, an LCCS would be more cost effective for consumers if it lowered capacity market prices by just $40/MW-day.

## 5.2  ANALYSIS

**Quantity of Capacity Needed, Supplied by Standards**

The collective RPS's in PJM states require 14% of energy generation to be supplied by renewable resources by 2026 [17].  To meet this collective RPS, approximately 105,000 GWh of renewable electricity per year are required [17].  If the renewable portfolio is filled exclusively with wind, it would require 40 GW of nameplate wind capacity assuming a capacity factor of 30% [14].  With an ELCC rating of 13%, this would generate approximately 5 GW of ELCC.

This 5 GW of ELCC created by the RPS is likely to be less than the capacity of units that are expected to be retired this decade.   Between 2011 and 2019, 25 GW of capacity is scheduled

to be retired in PJM, with an additional 15 GW of capacity at risk of retirement[6] [14].  Capacity

could be further shortened if the modest growth in demand, 1% per year through 2030 [18], is

realized.

Ideally, demand side management (DSM) would supply the shortfall.  However, it

appears likely that DSM supply in PJM may have reached a plateau. Offers peaked at 21 GW in

2015/2016 auction and dropped to 16 GW in the 2016/2017 auction and then to 13 GW in the

most recent (2017/2018) auction [11].

In theory, PJM's capacity market is the financial mechanism that should procure the

generators needed to satisfy the shortfall.  However, for the capacity market to procure

significant amounts of new build capacity, prices must rise substantially.  PJM estimates that the

gross Cost of New Entry (CONE) for a combined cycle[7] gas fired power plants is \$390/MW-day

[19].  When profits from energy and ancillary service markets are taken into account, PJM

estimates the net CONE to be \$335/MW-day [20].  Net CONE is the net cost of capacity given

the energy and ancillary service market value of the power plant.  Essentially, capacity prices

would have to increase to \$335/MW-day[8] to incent new (gas) power plants.  Historically,

capacity prices have averaged ~\$85/MW-day [11].

If capacity prices increase from ~\$85/MW-day to \$335/MW-day to incent new capacity,

the costs to consumers will increase by approximately \$15B.  This would amount to an increase

of \$20 per MWh delivered in the PJM region, or about a 40% increase in the total wholesale cost

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[6] The average capacity-weighted forced outage rate (FOR) of steam power plants in PJM is 10% [13].  The ELCC of the coal plants scheduled for retirement or at risk of retirement would be 22.5 GW, and 13.5 GW, respectively.

[7] Brattle's CONE estimates show that combined cycle units' capital costs are now only slightly more expensive than simple cycle turbines.  Because of the small difference in capital costs and the revealed preference of developers to build combined cycle units [10], we focus this research on NGCC's as the default option for new generators.

[8] Energy and Ancillary Services (E&AS) estimates are based on the performance of generators for the three previous years.  For the 2017/2018 auction, the years of 2011 through 2013 were used to estimate E&AS revenue [13].

per MWh delivered.

**Quantifying the Costs and Required Capacity Benefits of an LCCS**

If generators that ran at a constant output (nuclear for example), were exclusively used to fulfill the RPS, approximately 13 GW of capacity would be supplied in addition to 105,000 GWh of carbon free electricity per year (assumed capacity factor of 90%). However, coal fired power plants with CCUS theoretically have the ability to temporarily boost output by shutting down the sequestration process [21]. This would boost peak electrical output by approximately 25% [22]. If the RPS was filled exclusively with CCUS plants, then the capacity delivered could be as high as 16 GW[9].

Estimating how this capacity supply would affect capacity markets is not straightforward. Capacity market models do not exhibit a high degree of accuracy because the market is so volatile. Instead of modeling the market, we estimate how much prices in capacity markets must decrease in order to make up for the premium paid for low carbon capacity. In Table 5-1 below, we show an example for quantifying the premium paid for low carbon capacity.

Table 5-1: Example for Costs and Capacity Supplied by RPS and LCCS

| | RPS | LCCS |
|---|---|---|
| LCOE [$/MWh] | 100 | 120 |
| Energy Supplied [GWh] | 105,000 | 105,000 |
| Cost for Energy [2012 USD] | $ 10.5 B | $ 12.6 B |
| ELCC Supplied [GW] | 5 | 13 - 16 |

Note: We assume the cost of wind is $100/MWh including variability and transmission costs. We assumed a cost of $120/MWh for the cost of the new low carbon source. The ELCC supplied from the low carbon source varies because of the ability of CCUS plants to temporarily pause the sequestration process and boost output. ELCC supply of the RPS was calculated assuming a 13% ELCC.

Using the assumptions in Table 5-1, the LCCS would cost approximately $2.1 B more but supply approximately 8 to 11 more GW of capacity than an RPS. Figure 5-1 below shows the supply and demand curves for the 2014/2015 auction year. To save consumers the $2.2 B from our

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[9] Coal plants with post-combustion capture typically are designed to capture 90% of the emissions from the plant. In this research we neglect these emissions noting that the variability of wind power plants decreases the amount of carbon emissions off-set as well [41][42][43].

example in Figure 5-1, the extra capacity supply would have to drive down capacity prices by

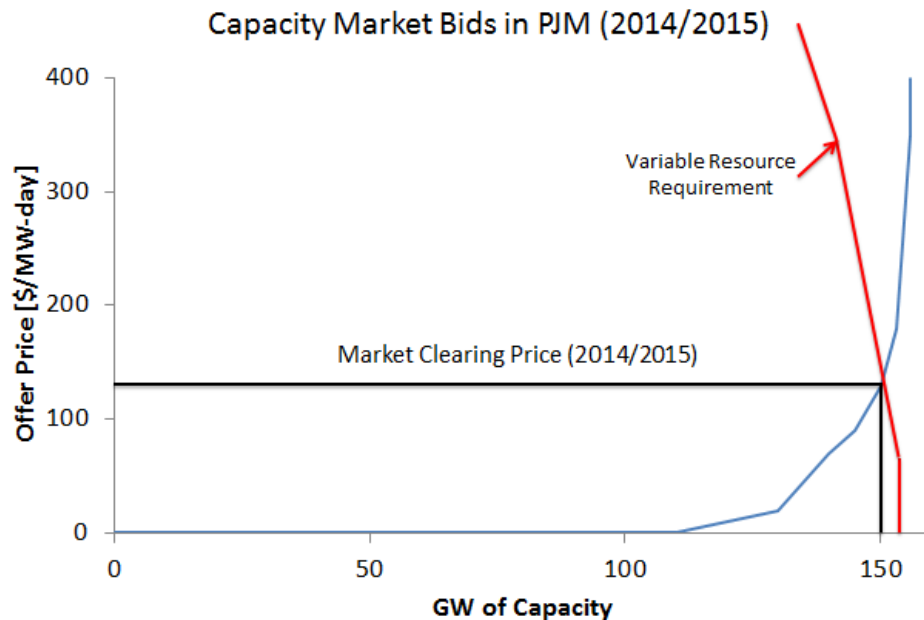$40/MW-day (assume 165 GW of capacity demand).



Figure 5-1: Supply and demand of capacity in the 2014/2015 PJM capacity auction. The Variable Resource Requirement is the downward sloping demand curve constructed by B. Hobbs [23]. The VRR is designed to reduce the volatility of capacity markets.

The costs in Table 5-1 above are just an example. As described well in the literature, the LCOE of renewables is dependent on the values of the analyst [24]. This is particularly true for nuclear, where LCOE is largely a function of capital cost, years needed for construction, and the discount rate assumed [25]. CCUS costs are uncertain because the first large scale plants are just now under construction [26].

Because the LCOE of low carbon energy is uncertain, we present our results as a function of the difference between and LCCS and RPS. For example, if energy from the low carbon capacity source is $20/MWh more expensive than energy from wind, how much would capacity prices have to decrease in order for technology agnostic, cost minimizing consumers to be indifferent between the two policy scenarios?

In Figure 5-2 below, we show how much capacity prices must decrease in order to make

up for the premium paid for low carbon capacity. We assume that the cost seen by consumers for either renewables or low carbon capacity would be equivalent to the LCOE. Table 5-1 above is an example of these quantifications.

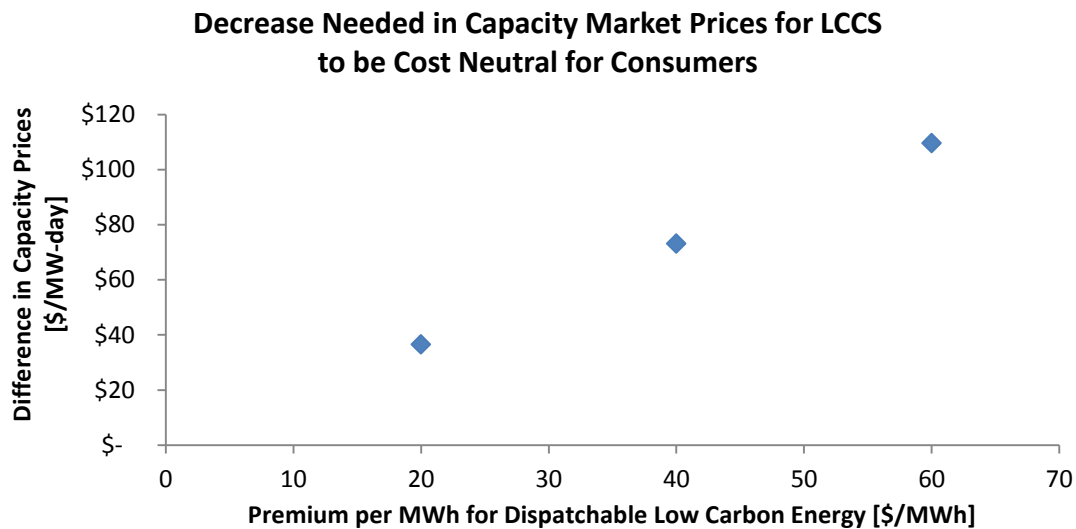**Decrease Needed in Capacity Market Prices for LCCS to be Cost Neutral for Consumers**



Figure 5-2: Savings in capacity prices that must be realized in order for consumer costs to be unaffected. An LCCS that provides the same amount of energy as the RPSs required in PJM would decrease capacity prices by supplying ≥10 GW more capacity than an RPS.

**Ensuring that Low Carbon Energy is Supplied in Addition to Capacity with an LCCS**

When comparing the costs of policies, we assumed that the cost of energy to consumers of both renewable energy and dispatchable energy would be equal to the LCOE. Furthermore, we assumed that power plants would be dispatched according to their technological capability (i.e. dispatchable plants would achieve a capacity factor of ~90%). In this section, we describe how low carbon capacity might be procured with an LCCS and the implied risks for the energy generated.

Typically with an RPS in restructured markets, renewable energy is procured through renewable energy certificates (REC) [27]. The REC market fosters competition to encourage the development of the lowest cost renewable energy possible. The sum of the revenue received by

developers through energy markets, subsidies, and REC's should be approximately equal to the levelized cost of the energy, in the absence of a market failure.

The market mechanism we examine to directly procure capacity for an LCCS would be a new low carbon capacity market. This market would directly procure a fixed amount of low carbon capacity very much like the capacity market currently in place in PJM except that it would be limited to new low carbon generators. This market mechanism utilizes market forces to procure the lowest cost capacity given a generator's value in energy markets.

However, an issue for this market structure that directly pays only for capacity is that additional policies are needed to ensure that the LCCS plant dispatches before carbon emitting power plants. We assume in this research a gas price of $6/MMBTU, and the relatively low marginal energy costs of the low carbon generators would assure that the generator would dispatch. However, the marginal costs of CCUS plants may be higher than some existing carbon emitting power plants because the sequestration process is inherently energy intensive. If gas prices are low (~$4/MMBTU) and EOR revenue is not available, we estimate that the CCUS plant would be dispatched rarely and have a capacity factor of only 35%.

A number of policies could be used to ensure that LCCS power plants dispatch and supply low carbon energy generation regardless of market conditions. For example, some system operators consider wind power "must run" unless the wind power needs to be curtailed for grid stability reasons [28]. Also, wind plants receive energy subsidies, such as the federal production tax credit. This effectively ensures that wind energy is dispatched, even when energy market clearing prices are (slightly) negative [28].

One potential policy mechanism for ensuring LCCS plants are dispatched is the use of contracts for differences (CfD). A contract of this sort redirects some of the financial risk for the

plant owner/operator onto the state which agrees to monetarily "fill in" any disparity in the wholesale price for electricity and the marginal cost of energy supply. When the converse is true and the marginal cost of energy supply is below the market clearing price, the owner/operator is obligated to pay the difference to the state. The major benefit of this arrangement is that the plant will always be dispatched and the state bears the risk to ensure low carbon energy is supplied. The risk to the state is relatively small because the marginal costs of a CCUS plant are only slightly higher than carbon emitting power plants. We find that a small EOR payment or subsidy ($10/MWh) would place CCUS plants ahead in the dispatch stack of carbon emitting power plants.

Because several mechanisms can be used to reduce the relatively small risk that LCCS plants do not dispatch, we assumed plants dispatched according to their technical capability. Furthermore, we assumed that the cost of the LCCS energy could be approximated by the LCOE. The revenue received by LCCS generators from energy market revenues, necessary energy subsidies, and capacity payments would be approximately equal to the LCOE of the energy supplied by the LCCS.

**Quantifying the Competitiveness of Low Carbon Capacity Options – Net Cost of New Entry (Net Cone)**

Per current practice in PJM's capacity market, the metric we will use to evaluate the economic competitiveness of a low carbon power plant's capacity is net Cost of New Entry (net CONE) [20]. We assume that capacity would be procured through an auction where low carbon generators bid their net CONE (defined below). The net CONE is quantified by fixed costs (PJM refers to these as "avoidable costs" [14]) less profits made in energy markets [14]. We estimate the net CONE on a per MW basis using the equation below.

$$NetCONE \left[\frac{\$}{MW_{ELCC}}\right] = \frac{Present\ Value\ (Owner's\ Fixed\ Costs - Energy\ Market\ Profits)}{Present\ Value\ (MW_{ELCC})}$$

Owners fixed costs are a sum of construction, accrued interest, and fixed O&M. Energy market profits are a function of revenue made in energy service markets less marginal costs (variable O&M and fuel costs). We do not take into account ancillary service market revenue. We estimate costs using the financial assumptions from Brattle for PJM's official Cost of New Entry (CONE) estimates: 8% after tax weighted average cost of capital, 20 year MACRS depreciation schedule, a federal tax rate of 35%, and a state tax rate of 10% [19].

To estimate how generators would profit in energy markets, we used an hourly economic dispatch model of the generators in PJM. Marginal power plant costs (fuel and variable O&M) and carbon intensities for each region were obtained from Ventyx Velocity Suite. The dispatch model calculates marginal costs for all generators, then dispatches the least expensive generators to meet load. The dispatch model does not take into account transmission, thermal, and security constraints.

Because we are examining a plausible near future, we removed 18 GW of coal capacity from the dispatch stack. To decide which generators to remove, we relied on the PJM 40/400 rule for the power plants most at risk of retirement (over 40 years old and small than 400 MW) [12]. More information on the dispatch model for PJM is given in the previous chapter.

**Assumptions for New Power Plants**

Table 5-2 below shows our assumptions for estimating the owner's fixed costs and profits made in energy markets. The assumptions are based on the most recent data available from literature cited in the table below. Like all economic analyses, the preferences of the analyst can lead to a wide range of results [24]. Our goal is to quantify (to first order) the net cost of capacity given the market value of the energy contribution for competing technologies.

The assumptions have a mix of point estimates and a range estimates. We varied the parameter(s) which had the greatest effect on their cost per MW of capacity offered. The price of natural gas alone can dominate energy profit estimates because it sets market clearing prices for most hours in energy markets. However, we did not vary the price of gas because higher or lower market clearing prices would help or hurt all of the technologies studied. We assumed the price of natural gas was fixed at $6/MMBTU, the EIA estimate for 2020 [29]. Of course, natural gas plants would be greatly affected by variation in natural gas prices. However, we do not show results sensitive to natural gas because it known that gas plants have the lowest cost of new entry. We show NGCC plants here for reference.

For renewables, a wide range of ELCC can be assumed. In some regions with low penetration, the ELCC of wind can be approximated by its capacity factor [5]. However, wind does not correlate well with load in the USA, and wind in PJM had an ELCC rating of 13%. We assumed a fixed cost for the capital costs of renewables because the ELCC rating has the most pronounced effect.

For CCUS, there are multiple uncertain assumptions. Capital costs are currently unknown because the first large scale plants are now under construction [26]. Our assumptions are based on estimates from the literature [30], but these are for nth of a kind plants. Early examples of new pollutant control technologies tend to increase in cost after the first of a kind [31] before asymptotically approaching the nth of a kind cost. Given the uncertain price of oil, it is also unknown how much revenue should be assumed for enhanced oil recovery. A rule of thumb is that the price of each MCF of $CO_2$ is around 2-3% of the price of a barrel oil [32] which equates to ~$35/tonne at $95/barrel. We assume a range from $0 to $60/t $CO_2$. We discuss the overall net emissions from CCUS after we present the results for net CONE.

Table 5-2: Capital Costs, Maintenance Costs, and Lifetime of Plant ($2012 USD)

| | NGCC [20] | Wind [33] | Solar PV [34] | Nuclear [25] | Coal with CCUS [35] [36] |
|---|---|---|---|---|---|
| Capital Costs $/kW_{Nameplate} | 1,200 | 1,940 | 3,000 | 5,500 – 8,500 | 3,600-5,500 |
| Fixed Maintenance Costs ($/kW-year) | 17 | 25 | 17 | 60 | 100 |
| Fuel Costs ($/MWh) | 40 | 0 | 0 | 7 | 27 |
| Total Marginal Costs ($/MWh) | 43 | 0 | 0 | 7 | -25 - 30* |
| Financial Lifetime of Plant (Years) | 20 | 20 | 20 | 30 | 30 |
| Construction Time (Years) | 3 | 2 | 2 | 7 | 4 |
| ELCC* | .95 | 0.13 – .25 | 0.38 | .975 | .9 – 1.1 |
| Energy Market Profits ($/kW-year) | $15 | $108 | $82 | $245 | $67 - $500* |

Notes: *Marginal costs and energy market profits from CCUS plants vary with EOR payments. Without EOR revenue, marginal cost of CCUS would be approximately $30/MWh. We varied EOR payments from 0 to $60/tCO$_2$, which would allow CCUS plants to have a marginal cost as low as -$25/MWh. This would substantially increase energy market profits as shown in the table. ELCC estimates were estimate d

Below in Figure 5-2, we show the Net CONE of various low carbon technologies according to
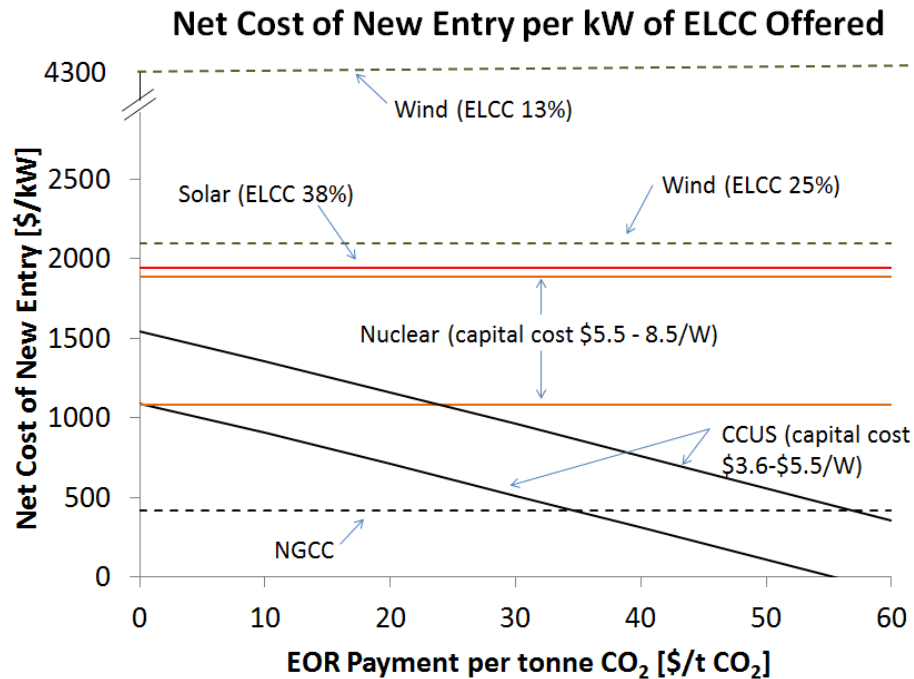
the assumptions from Table 5-2.

**Figure 5-3:** Net CONE of various low carbon technologies.

Figure 5-3 above shows CCUS is likely to be the most competitive technology given our assumptions. Costs of renewables are dominated by the assumed ELCC. It should be noted that ELCC of wind and solar diminishes with increasing penetrations [37].

**Note on Emissions from Coal Plants with CCUS**

In the analysis above, we assumed an LCCS could achieve the same emissions reductions as an RPS because eligible plants would generate substantial amounts low carbon electricity. An issue for CCUS as a carbon mitigation strategy is that $CO_2$-flood EOR may have greater net emissions than other low carbon power plants because it increases the overall oil supply [38]. Here, we do not account for the emissions produced by combusting the oil because we are exploring this policy as a means to meet EPA mandated emission reductions for the power sector, comparing an RPS to an LCCS. Section 111(d) regulates power plant emissions, and we assume that emissions reductions from the transportation sector are achieved through other regulations, such as Corporate Average Fuel Economy (CAFE) standards. Current U.S. policy

of emissions accounting is not based on where carbon is supplied but where it is combusted [39]. Therefore, we assumed that CCUS is an eligible technology to help fulfill SIPS even though its impact on overall emissions is unclear.

## 5.3 DISCUSSION

We examined the implications of lowering the $CO_2$ emissions in PJM with a Low Carbon Capacity Standard (LCCS) instead of an RPS. An LCCS requires LSE's to procure a certain amount of low carbon capacity as a means to ensure that both capacity and low carbon energy is supplied. We examined this policy as an alternative to an RPS that does not supply capacity that is commensurate with the amount of energy supplied.

We quantified the amount of capacity supplied by the RPSs in PJM and showed that capacity could become undersupplied before 2020. 25 GW of capacity are scheduled to retire by 2019 and we estimated that the RPS will supply only 5 GW of capacity. An RPS would not necessarily cause an increase in capacity prices to net CONE, but it would increase the likelihood of capacity market clearing price increases by way of undercutting profits in energy markets while supplying little capacity. If new generators are needed to supply capacity, capacity market prices will likely rise from current prices, ~$85/MW-day, to PJM's projection of net CONE, $335/MW-day. We estimate that raising capacity prices to this level would cost consumers $15 B annually and raise the wholesale cost of electricity in PJM by 40%.

An LCCS would lower dependence on capacity markets by requiring LSE's to procure capacity through "self-supply" [14]. However, energy from CCUS and nuclear plants is at present higher cost than from wind generators. We quantified the cost differences between the policies, by estimating the LCOE. If the energy from an LCCS costs on average $20/MWh more than energy from an RPS, then the annual premium would be approximately $2.2 B. In order for

consumers to be better off with an LCCS in this example, capacity prices would have to decrease by $40/MW-day. The LCCS could reduce capacity prices by supplying at least ~10 GW more capacity than an RPS. Given the steepness of the supply curve for capacity, it is reasonably likely that 10 GW of capacity would lower capacity prices an appreciable amount. The supply curve for capacity in PJM typically increases by over $300/MW-day over the last 10 GW of capacity offered [9].

We then showed that if an LCCS were enacted, CCUS plants would likely have the lowest cost per MW of capacity based on net CONE estimates, if the revenue from EOR exceeds $30-45/ton of $CO_2$. Despite uncertainty in EOR revenue, our analysis shows CCUS to be strictly dominant compared to solar and wind on both a gross and net CONE basis across the range of capital cost and EOR revenue assumptions. Net CONE estimates for CCUS were lower than for nuclear in all but those scenarios with high CCUS capital expense and low EOR revenues, and were cost-competitive with NGCC under the most favorable ($3600/kW and EOR credit >$35/t) scenarios examined.

The ability to switch off carbon capture for purposes of temporarily increasing capacity is a topic which requires further analysis to properly evaluate cost effectiveness. However, our first order analysis indicates that this ability reduces net CONE by roughly $300-400/MW-day for CCUS facilities. We also acknowledge that there are complex market dynamics of implementing a LCCS over an RPS, or vice versa, which are beyond the scope of our analysis.

Our purpose has been to highlight the potential system costs (energy and capacity) of implementing an LCCS instead of an RPS in the PJM market. We have shown that net CONE (a metric that includes the value of capacity) is more useful in evaluating the all-in system costs of policies than LCOE. We have noted throughout this work that the assumptions and values of the

analyst can heavily influence the outcome of any cost estimate. However, this work suggests that, at a minimum, the costs of supplying adequate capacity to ensure acceptable loss of load should be accounted when analyzing alternative emission reduction scenarios and that the use of more comprehensive metrics such as net CONE should be preferred where data are available.

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